Reservoir quality of deeply buried sandstones – a study of burial diagenesis from the North Sea

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Preface

This thesis entitled "Reservoir quality of deeply buried sandstones – a study of burial diagenesis from the North Sea" has been submitted to the Department of Geosciences at the University of Oslo in agreement with the requirements for the degree of Philosophiae Doctor (Ph.D.). The work follows in the tradition of diagenesis and compaction related research fronted by Professor Knut Bjørlykke for decades.

The results are mainly based on various types of well data from the North Sea region. Petrophysical wellogs, core plug analysis and core samples provide the basis for most of the work herein.

The thesis consists of an introduction together with five individual papers and one extended abstract. The introduction gives a review of the scientific background, main objectives, summary of the papers enclosed, and finally concluding remarks of the study. Two of the papers are published whereas the remaining have been submitted to international journals. The focus of the work is to gain a better understanding of the factors controlling reservoir quality distribution in deeply buried sandstones.

The first two enclosed paper are regional papers that document the diagenetic controls on reservoir quality in deeply buried Upper Jurassic sandstones of the South Viking Graben and Central Graben respectively. Paper 3 Presents a model for the formation of grain coating chlorite in the Triassic Skagerrak Formation based on data from the Ivar Aasen field on Utsira High. Paper 4 studies the compaction trend in the Etive Formation. Extended abstract 1 investigate whether grain to grain pressure solution may have been a source of quartz cement in Precambrian orthoquartzites. Extended abstract 2 presents the pre-drill assesment of the deeply buried Stirby prospect (well 24/12-6S) in the South Viking Graben. In addition five conference abstracts related to the above mentioned papers have been presented through the course of this Ph.D.

Two additional papers that are not directly related to the main scope and objectives of this thesis are also enclosed. Paper 5 presents the first attempt of a regional seismic stratigraphic framework of the Triassic in the Central North Sea. Paper 6 presents a modeling study related to CO_2 storage.

Acknowledgement

This thesis would not have been possible without the support and goodwill of a number of people. First of all I would like to thank my supervisor, Associate professor Jens Jahren, for the opportunity and for his advice and contributions to this thesis. I am also especially grateful for the support and knowledge of Professor Knut Bjørlykke. He has been an inspiration and invaluable discussion partner throughout my studies.

I owe my thanks to a number of colleagues throughout the course of my studies. Øyvind Marcussen, Delphine Croizé, Manzar Fawad, Erlend Morisbak Jarsve and Brit Thyberg are present and former colleagues at the Department of Geoscience which have contributed with valuable input and a pleasant working environment. I would also like to acknowledge Berit Løken Berg and Michel Hereemans for technical assistance.

A number of knowledgeable people in the industry have contributed and inspired this work in numerous ways. I would like to give a special thanks to Knut Pederstad, Odd Ragnar Heum, Peter Keller, Per Erik Øverlie, Roger Flåt and Ronald Sørlie.

Finally, to "my better half" Frøydis, thank you for your encouraging support and patience.

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Paper 2: Maast, T. E., J. Jahren, and K. Bjørlykke, 2011, *Diagenetic controls on reservoir quality in Middle- to Upper Jurassic sandstones in the South Viking Graben, North Sea*: AAPG Bulletin, v. 95, p. 1937-1958.

Paper 3: Maast, T. E., R. Sørlie and J. Jahren, (manuscript), *Reservoir quality prediction and the formation of grain coating chlorite in semi-arid continental sandstones. Examples from the Triassic Skagerrak Formation, Ivar Aasen field, North Sea.*

Paper 4: Marcussen, Ø., T. E. Maast, N. H. Mondol, J. Jahren, and K. Bjørlykke, 2010, *Changes in physical properties of a reservoir sandstone as a function of burial depth – The Etive Formation, northern North Sea*: Marine and Petroleum Geology, v. 27, p. 1725-1735.

Extended Abstract 1: Maast, T. E. and J. Jahren, 2013, *Is grain-to-grain pressure solution contributing to quartz cementation in sandstones?* four page extended abstract submitted to the 75th EAGE Conference, 10-13 June 2013, London, UK.

Extended Abstract 2: Gowers, M. B., L. Arnesen, B. Berntsen, E. Hagen, T.E. Maast and K. Pederstad, 2009, *The Stirby prospect – a new look at the deep Jurassic in the South Viking Graben*, Exploration Revived, Bergen.

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Additional contributions

Paper 5: Jarsve, E. M., T. E. Maast (manuscript), *Seismic stratigraphic sub-division of the Triassic succession in the central North Sea – integrating seismic reflections and well data.*

Paper 6: Pham, V. T. H., T. E. Maast, H. Hellevang and P. Aagaard, (2011). *Numerical modeling including hysteresis properties for CO2 storage in Tubåen formation, Snøhvit field, Barents Sea*. Energy Procedia. p. 3746- 3753.

Introduction

Study area and data

In 1966 the first exploration wells were drilled in the Norwegian North Sea. The first discovery was made the same year (Balder field, well 25/11-1), followed by minor discoveries (7/11-1, 1/3-1, 2/3-1) and oil shows that proved the potential of the region. In 1969 this potential was released with the discovery of the giant Ekofisk field (well 2/4-2). Ekofisk became the first field to be put in production in 1971. Since that time more than 1150 exploration wells have been drilled in the norwegian North Sea alone. As a consequence of the petroleum exploration the stratigraphy and geological evolution is well understood and defined. The Mesozoic reservoir rocks have essentially been passively subsiding from the Cretaceous, but are due to Late Jurassic rifting presently buried to very different depths. The North Sea region therefore provide an excellent natural laboratory for studies of diagenetic processes as a function of varying stress and temperature conditions.

In the present study petrographic, petrophysical and sedimentological methods are integrated. Data is taken from the extensive North Sea database (Figure 1).

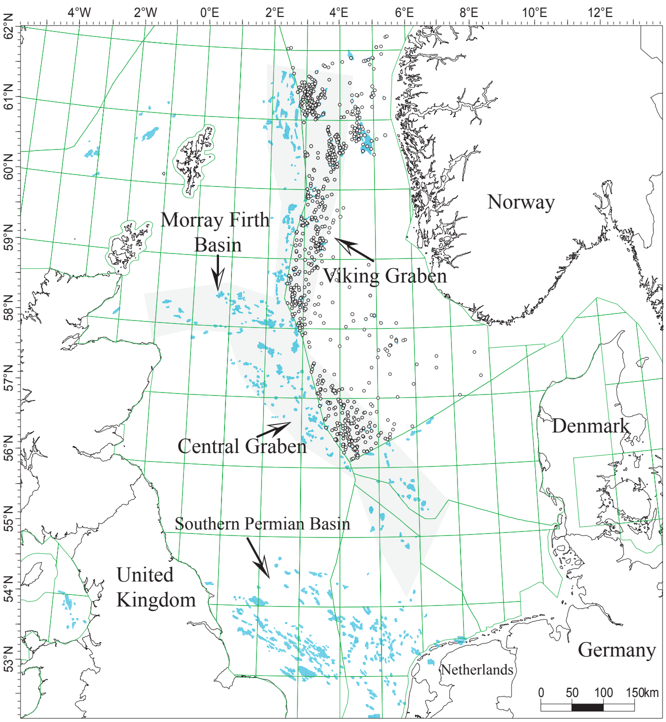


Figure 1. Overview of the Jurassic North Sea tripple rift and Norwegian exploration wells.

Hydrocarbon fields and discoveries
Exploration wells

Scope and objectives

The scope of this study has been to investigate the parameters that control reservoir quality as a function of increasing stress and temperature. The main variables are related to primary sediment composition and texture, which is a function of depositional facies, climate and provenance. In this study sandstones buried from 2 to about 5 km depth have been studied. Special emphasis has been focused on reservoir quality in deeply buried (> 4km) sandstones. In such sandstones grain coatings are vital for preservation of porosity. Other potential porosity and permeability preserving mechanismns that inhibit quartz cementation have also been investigated.

Scientific background

During the 1980's and 90's especially fundamental findings and conceptual breakthroughs were made that revolutionized clastic sandstone diagenesis and led to the development of a new generation of reservoir quality predictive tools (Bjørkum, 1996; Bjørkum et al., 1998; Bjørlykke, 1983, 1984, 1994; Bjørlykke and Egeberg, 1993; Bjørlykke et al., 1988; Bjørlykke et al., 1992; Bjørlykke et al., 1989; Bjørlykke et al., 1986; Lander and Walderhaug, 1999; Nedkvitne et al., 1993; Oelkers et al., 1996; Ramm et al., 1997; Walderhaug, 1994a, b; Walderhaug, 1996). These concepts and related controversies have recently been reviewed by Taylor et al. (2010) and Ajdukiewicz and Lander (2010). It has been known for some time that porosity loss at depth is mainly a function of mechanical compaction and quartz cementation (Bjørlykke et al., 1989). However, prior to 1990 these processes were poorly understood, especially the process of quartz cementation (McBride, 1989). Quartz cementation was typically linked to grain-to-grain pressure solution or migrating quartz saturated fluids. Porosity in deeply buried sandstones were attributed to the generation of secondary porosity by dissolution of unstable grains or early non-quartz cements by the leaching effect of migrating organic acids (Burley, 1993). Some of these concepts are still being published (Marchand et al., 2002; Sheldon et al., 2003).

By contrast, the current paradigm state that most deep porosity is preserved primary porosity. Preservation of porosity at greater burial is due to inhibition of quartz cementation (syntaxial overgrowths). The process of quartz cementation is a slow, continuous process related to temperature. Quartz cementation is precipitation controlled in most sandstones rather than controlled by pressure solution or episodic fluid fluxes (Bjørlykke and Egeberg, 1993). These findings have crucial implications for reservoir quality prediction and are supported by large amounts of data indicating the following:

1) The effectiveness of grain coatings on quartz grains (e.g. chlorite, microquartz) as an inhibitor of quartz cementation.
2) Vertical effective stress, although a fundamental factor in mechanical compaction, cannot be used as a predictor of porosity for lithified sandstones.
3) Meteoric water may alter the primary mineralogy during shallow burial. Ones sandstones are buried below the reach of meteoric water (10-100 meters), fluid flow processes have negliable effect on diagenesis and the sandstone system should be considered as closed.
4) Secondary porosity related to dissolution of framework grains and/or cements is most commonly volumetrically minor (<~5%) and associated with precipitation of authigenic clays causing a neglectable increase in total porosity, but rather a significant decrease in permeablity.
5) The hypothesis and widely held belief that hydrocarbon pore fluids preserve porosity by inhibiting quartz cementation is not supported by detailed data and does not represent a viable predictive model.

The controversies of the past still persist in the literature justifying a brief review of the basic theoretical concepts of sandstone diagenesis/compaction including porosity preserving mechanisms in deeply buried sandstones and state-of-the-art reservoir quality predictive tools.

Sandstone compaction

The term compaction refers to the diagenetic processes that reduce the porosity and bulk volume of the sediments and increase their density. The importance of subdividing the compaction of quartz-rich sandstones into a mechanical regime and a chemical regime lie at the core of successful reservoir quality prediction (Bjørlykke, 2003; Lander and Walderhaug, 1999) (Figure 2). In the mechanical regime the effective stress cause reorienting, breaking and consequently a denser and more stable packing of sand grains with increasing stress, a process referred to as mechanical compaction. As burial temperatures reach about 60-80°C the precipitation rate of quartz will become sufficient for quartz cementation to strengthen the rock and mark the transition from mechanical to chemical compaction (Bjørlykke, 2003; Bjørlykke and Egeberg, 1993; Walderhaug, 1994b). Quartz cement increases the strength of the sandstone grain framework substantially soon after cementation commences. Therefore increased effective stress generally does not cause further mechanical compaction in the chemical regime and thermodynamics and kinetics have to be employed for successful reservoir quality prediction. The mechanical- and chemical compaction regimes thus refer to whether compaction is sensitive to stress or temperature. Even so, it is important to be aware that there are important chemical processes taking place in the mechanical regime. Feldspar dissolution and certain clay mineral transformations are examples. These reactions however cause little change in the overall porosity. The precipitation of early carbonate cements also seriously affect the reservoir properties in many types of sandstone and must be accounted for.

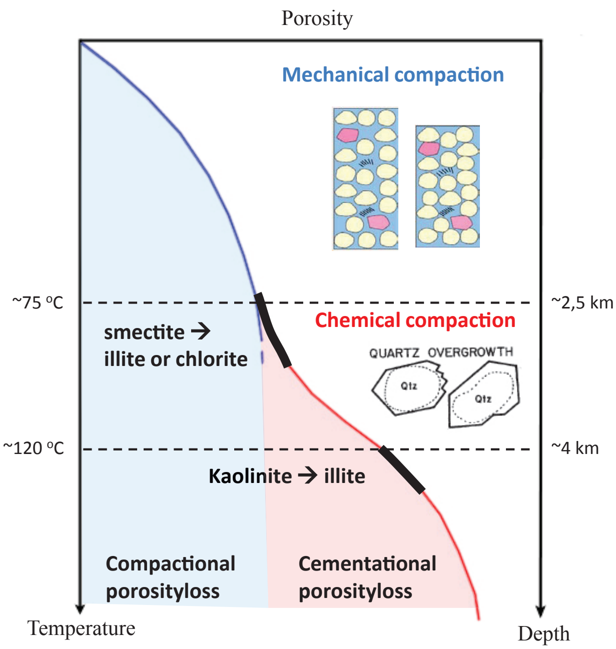


Figure 2. Overview of important diagenetic processes in clastic sandstone reservoirs.

Mechanical compaction

Mechanical compaction cause a gradual decrease of the porosity and the inter granular volume (IGV) during shallow burial of sandstones. The IGV, i.e. sum of porosity, cement and matrix, has been an especially useful measure that has improved the ability to measure and model sandstone compaction (Ehrenberg, 1995; Houseknecht, 1987; Lundegard, 1992). In clean sandstones these two measures will coincide, however in argillaceous sandstones the porosity will be lower than the IGV due to the matrix content.

An important discovery was the observation that the IGV will stabilize at about 26% which corresponds to cubic close packing (CCP) of spheres (Paxton et al., 2002; Ramm, 1992). This means that mechanical compaction has the potential to reduce the porosity from about 40-42% upon deposition down to about 26% in clean, well sorted, quartz rich sandstones but higher values are not uncommon. For sandstones containing significant portions of matrix the porosity may be lower, however the IGV will also in such lithologies usually stabilize around 26%.

In general sandstone composition and texture govern the rate of mechanical compaction in that poorly sorted sands compact more rapidly than well sorted sands, coarse grained sands compact more rapidly than fine grained sands and mineralogically immature sands compact more rapidly than mineralogically mature sands (Figure 3) (Chuhan et al., 2002; Fawad et al., 2011; Fawad et al., 2010; Pittman and Larese, 1991). In natural sandstones textural heterogeneties cause porosity, even in fairly clean, homogenous sandstones, to scatter about +- 5% around the average within a given sandstone sequence. In poorly sorted and argilaceous sandstones this variation may be even larger.

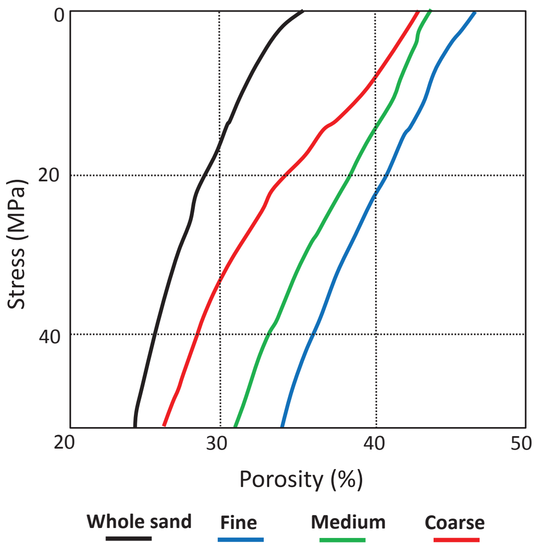


Figure 3. Experimental compaction trends illustrating the effect of grain-size and sorting. Figure from Fawad et al. (2010).

Quartz cementation

At burial depths corresponding to 60-80 °C the precipitation rate of quartz becomes sufficient to strengthen the rock and mark the transition from mechanical to chemical compaction (Bjørlykke, 2003; Bjørlykke and Egeberg, 1993; Walderhaug, 1994b). The precipitation of as little as 2-3% quartz cement is probably sufficient to stabilize the grain framework and cause no further depletion of the IGV. Porosity will continue to decline proportionally to the amount of quartz cement precipitated. Large amounts of data indicate that the source of quartz cement is local and that quartz grains are preferentially dissolved along stylolites and clay laminae due to increased quartz solubility at these interfaces, a mechanism referred to as Clay-induced dissolution (CID) (Oelkers et al., 1996; Oelkers et al., 2000; Walderhaug et al., 2004). Cementation sourced by dissolution along stylolites result in passive infilling of the pore space preserving IGV. If silica was sourced from grain to grain dissolution the grain framework would continue to compact causing the IGV to decrease further. Even deeply buried sandstones rarely have IGV values below 26% (Paxton et al., 2002), showing that grain to grain pressure solution is not significant in most sandstones. Dissolution along stylolites set up concentration gradients causing diffusion of silica into the interstylolite pore-space where precipitation takes place (Figure 4). Precipitation is normally the rate limiting step and consequently quartz cementation can be modeled as a function of the precipitation rate of quartz (Walderhaug, 1996). In certain extremely clean quartz sandstones where stylolite spacing is larger than 10-20 cm diffusion may become the rate limiting step causing gradients in the amount of quartz cement away from stylolites (Walderhaug and Bjørkum, 2003). Dissolution along stylolites and grain contacts is limited by the rate of precipitation, which is evidence that the system is geochemically closed. In sandstones with grain coatings the lack of quartz nucleation surfaces slows down the precipitation of quartz cement and the silica supersaturation builds up to the maximum level sustained by the stylolite dissolution process. If a sandstone system were chemically open, all the quartz grains along the stylolites would continue to dissolve and the silica would be transported out of the sandstone. The potential for mass

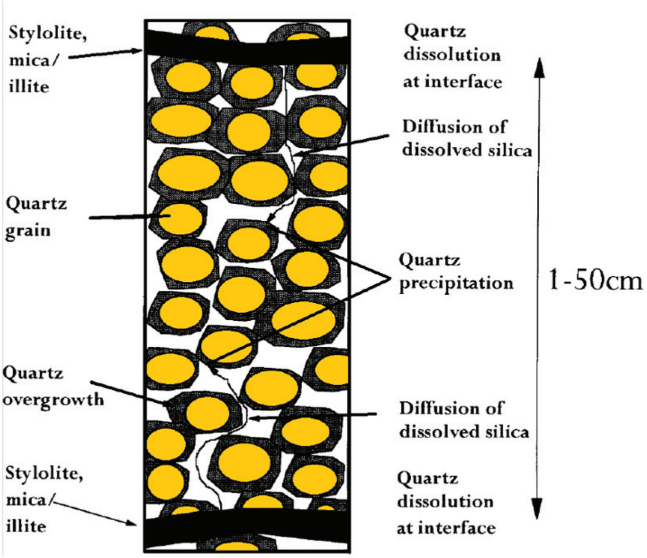


Figure 4. Schematic illustration of the clay induced dissolution (CID) model for quartz cementation in sandstones. Figure from Bjørkum et al. (1998).

transport of solids in solution in sedimentary basins is very small as far as advective transport is concerned (Bjørlykke and Egeberg 1993). The flow rate (fluid flux) of pore water is many orders of magnitude too low to be significant in terms of mass transport during burial (Bjørlykke, 1994; Bjørlykke and Jahren, 2012). The closed geochemical nature of deep burial diagenesis makes it possible to model cementation and porosity loss in reservoir rocks. The precipitation rate of quartz increases exponentially with temperature (Walderhaug, 1994a). Therefore the overall rate of cementation of a unit volume of sandstone will be controlled by the temperature history of the sandstone and the surface area available for cementation, which is a function of grain size, mineralogy and grain coatings (Walderhaug, 1996).

Grain dissolution reactions and clay mineral transformations

Dissolution of mineral grains and clay mineral transformations are important chemical processes that often have negative consequences for permeability, but may also lead to the generation of porosity preserving grain coatings. In sedimentary basins with a source of potassium (usually K-feldspar or mica), kaolinite and smectite become unstable during burial and react to illite and/or chlorite (Hower et al., 1976; Pearson and Small, 1988; Peltonen et al., 2008). Feldspar and mica grains are susceptible to leaching by meteoric water, causing minor secondary porosity and precipitation of an almost equal volume of kaolinite. The reaction takes place during shallow burial near the surface and requires a flux of meteoric water that constantly supply H^+ ions and remove the reaction products (K^+, Na^+) in the overall reactions:

$$\underset{\text{K-Feldspar}}{2K(Na)AlSi_3O_8} + 2H^+ + 9H_2O \rightarrow \underset{\text{Kaolinite}}{Al_2Si_2O_5(OH)_4} + \underset{\text{dissolved silica}}{4H_4SiO_4^{4+}} + 2K^+(2Na^+)$$

$$\underset{\text{Mica}}{2KAl_3Si_3O_{10}(OH)_2} + 2H^+ + 9H_2O \rightarrow \underset{\text{Kaolinite}}{Al_2Si_2O_5(OH)_4} + \underset{\text{dissolved silica}}{4H_4SiO_4^{4+}} + 2K^+(2Na^+)$$

After Bjørlykke et al. (1992)

Feldspar leaching is most intense in humid climates, such as the North Sea Jurassic, and in proximal, permeable sediments such as fluvial and marginal marine sandstones adjacent to a high where elevated groundwater levels may cause a hydrodynamic potential driving meteoric water flow into the basin. Meteoric water flow is much less important in deep marine sandstones and these therefore often contain less kaolinite. In climates with net evaporation, such as the North Sea Triassic and Permian, feldspar leaching will be less intense and limited to periods of floods (rain). During periods of drought evaporative concentration of the ground water may cause the precipitation of iron oxides and smectites and give rise to grain coatings and the characteristic redbed facies of these environments (Walker, 1967, 1976). In addition water containing clay particles infiltrated during floods will evaporate during drought and leave the particles on the grain surfaces forming potential seeds for later growth of grain coatings.

Kaolinite is susceptible to illitisation during deep burial (120-140 ºC), a process that is especially destructive for the permeability (Bjørlykke et al., 1992; Ehrenberg, 1990):

$$\underset{\text{K-Feldspar}}{2K(Na)AlSi_3O_8} + \underset{\text{Kaolinite}}{Al_2Si_2O_5(OH)_4} \rightarrow \underset{\text{Illite}}{KAl_3Si_3O_{10}(OH)_2} + \underset{\text{Quartz}}{SiO_2} + 2H_2O$$

After Bjørlykke et al. (1986)

Overall the illitisation of kaolinite is the most significant cause of depletion in reservoir properties along with quartz cementation in most deeply buried North Sea reservoirs (Bjørlykke et al., 1992; Giles et al., 1992). It is however vital that there is a source of Potassium in the sediments (i.e. K-feldspar, mica). In some Jurassic sediments where meteoric leaching has been especially intense, dissolving nearly all feldspar and mica, kaolinite may be stable to greater depths (Chuhan et al., 2000). In sediments deposited under semi-arid and arid climates kaolinite is less frequently present and smectite is usually the dominant clay mineral (Bjørlykke, 1983; Chamley, 1989). Smectite will transform to chlorite or illite or both between 60-90 °C.

$$\text{smectite} + Al^{3+} + K^{+} \rightarrow \text{illite} + Si^{4+} \quad \text{(Hower et al., 1976)}$$

$$\text{smectite} + \text{K-feldspar} \rightarrow \text{illite} + \text{chlorite} + \text{quartz} \quad \text{(Boles and Franks, 1979)}$$

Thus smectites may be a source of permeability reducing illite in semi-arid to arid environments (Leville et al., 1997; Platt, 1993; Sullivan, 1991), but smectites may also act as the precursor for chlorite coatings under such conditions (Hillier, 1994; Hillier et al., 1996).

Carbonate cementation

In continental environments with net evaporation carbonate cements (calcrete, dolocrete) may form as vadose (pedogenic) or phreatic (groundwater) minerals (Wright and Tucker, 1991). In modern environments such carbonate cements typically form where the annual precipitation is less than 650 mm/year and the average temperature is above 5 °C (e.g. Blatt et al., 1980). Pedogenic carbonates are linked to soil formation and are not very common in reservoir sandstones. Phreatic carbonates form due to concentration of ions in the groundwater due to weathering reactions and net evaporation. In general highland regions contain river- and groundwater with very low salinities. In lowland regions weathering reactions in the aquifer increase the salinity of river- and groundwater. If these river- and groundwater enter arid to semi-arid regions with annual net evaporation they may start precipitating phreatic cements.

Carbonate cements in the marine environment are usually derived from early marine cements or from biogenic carbonate materials, consisting of aragonite and high Mg Calcite (Bjørlykke et al., 1989). These minerals will transform to low Mg-Calcite during shallow burial (< 70 °C) (Saigal and Bjørlykke, 1987). Biogenic carbonate cements may be especially abundant where biological productivity is high and the clastic sedimentation rate is low such as in shelf/shallow marine sandstones. The evolution of pelagic carbonate organisms also contributes a potential source of carbonate cements in Upper Jurassic and younger sediment. Dispersed carbonate material within a sandstone will lead to local nodules (tens of cm up to a few meters) that locally reduce the net/gross, but have little effect on the overall reservoir performance. If the concentration of carbonate organisms is especially high along a surface, for example a flooding surface, a carbonate cemented horizon may develop that represent a significant baffle to fluid flow (e.g. Gibbons et al., 1993).

Porosity and permeability preservation in deeply buried sandstones

All of the diagenetic processes acting on reservoir sandstones described up to this point affects the reservoir quality. However, mechanical compaction and quartz cementation are the main process causing overall depletion in porosity during progressive burial in quartz rich sandstones. The preservation of porosity therefore relies on factors inhibiting quartz cementation and mechanical compaction. There are three main factors cited in the literature claiming to preserve porosity to great depths, these are grain-coatings, early hydrocarbon emplacement and fluid overpressure (e.g. Bloch et al., 2002). However, due to the relatively recent advances in the understanding of compaction processes, especially quartz cementation, there is a great deal of diverging and confusing reportings in the literature. As mentioned earlier there is growing consensus that hydrocarbon emplacement and fluid overpressure do not significantly affect the rates of quartz cementation in sandstones (i.e. Taylor et al., 2010). Hydrocarbon emplacement and fluid overpressure may however have other beneficial effects on the preservation of reservoir properties as will be discussed shortly.

Chlorite and several other grain-coating minerals with porosity-preserving effects have been recognized in sandstones (e.g. Heald and Larese, 1974). In the North Sea region the most efficient coatings reported are authigenic chlorite and microquartz (e.g. Ehrenberg, 1993; Ramm et al., 1997; Aase et al., 1996). These coatings usually form on framework grains authigenically during shallow burial (< about 70°C), due to the transformation of a precursor material such as smectite in the case of chlorite coatings (Hillier, 1994; Hillier et al., 1996; Aagaard et al., 2000) or spicules of the siliceous sponge Rhaxella Perforata in the case of microquartz coatings (Hendry and Trewin, 1995). Grain-coating chlorite has long been known for its porosity-preserving effect (Heald, 1965; Heald and Larese, 1974; Pittmann and Lumsden, 1968; Wilson and Pittman, 1977) and is the most widely described grain-coating mineral in the literature. Micro-crystalline quartz coatings (microquartz) are less frequently described in the literature compared to chlorite coatings, and probably

Table 1. Summary of the some of the literature on grain coating chlorite and microquartz.

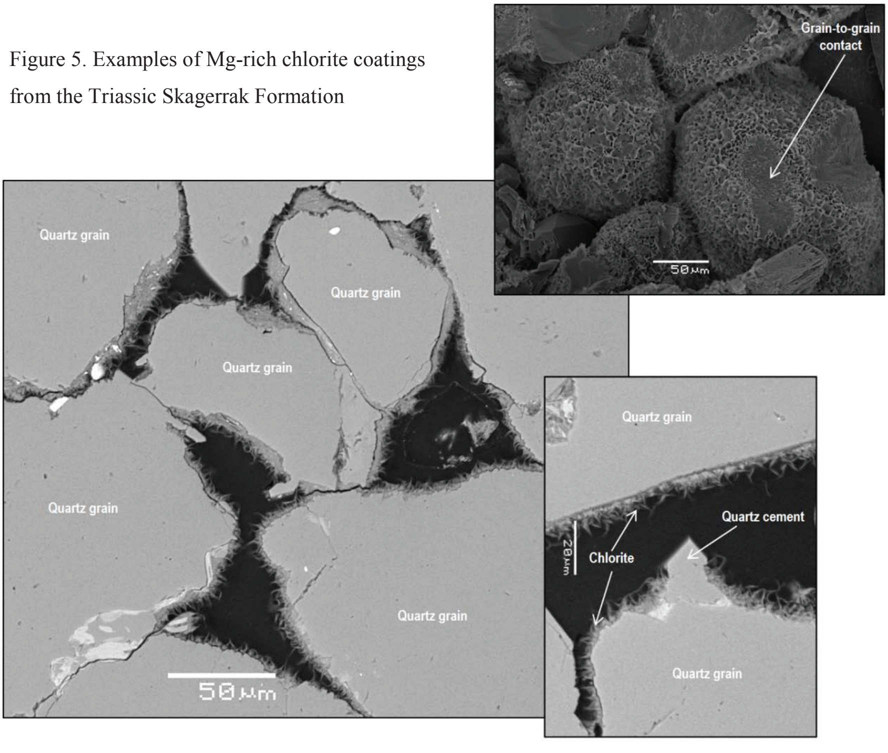
Grain coating mineral	Control: Depositional environment (DE) vs provenance (P)	References
Chlorite (Fe-rich)	DE: Shallow – marginal marine near Fe-rich, tropical river inputs	Ehrenberg (1993)
Chlorite (Fe-rich)	P: dissolution of volcanic rock fragments	Thompson (1979); Anjos et al. (2003)
Chlorite (Fe-rich), illite, illite/chlorite	P: Dissolution of volcanic ash	Strovoll et al. (2002); Humphreys et al. (1994)
Chlorite (Fe-rich)	DE: Confined turbidite channels	Houseknecht and Ross (1992)
Chlorite (Mg-rich)	DE: Eolian or sabkha sands associated with evaporates	Kugler and McHugh (1990); Thompson and Stancliffe (1990); Platt (1993); Ajdukiewicz & Nicholson (2010)
Chlorite (Mg rich)	DE: Terminal fluvial systems	Müller (1996); Sørlie (1996); (Humphreys et al., 1989; Jeans, 2006; Purvis, 1989)
Clay	DE: Burrowed shelf to offshore-transition sands	Wilson (1992); Worden et al.(2006)
Microquartz	DE: Rhaxella Perforata	Aase et al. (1996); Hendry and Trewin (1995); Ramm et al. (1997)

underreported because they may be hard to interpret from petrographic examinations due to their small size. Most of the published literature on microquartz is in fact from the North Sea region. Chlorite coatings are reported from a large number of settings throughout the worlds stratigraphy and sedimentary basins. The following review of chlorite coatings are concerned with the reportings from the North Sea region. For further reading some of the global literature on chlorites coatings are summarized in table 1.

Grain-coating chlorite

Two broad compositional categories of chlorite coating seem to exist, Fe-rich and Mg-rich chlorites (Hillier, 1994) (Figure 5). Fe-rich Chlorites are most common in marine environments, whereas Mg-rich chlorites are found in arid to semi-arid continental deposits characterized by net evaporation. The work by Ehrenberg (1993) is the most classical example of Fe-rich chlorite coatings in marine sediments from the North Sea (and Haltenbanken) region. Ehrenberg (1993) proposed that grain-coating chlorite is a consequence of synsedimentary concentration of precursor Fe-rich clay in shallow marine

Figure 5. Examples of Mg-rich chlorite coatings from the Triassic Skagerrak Formation



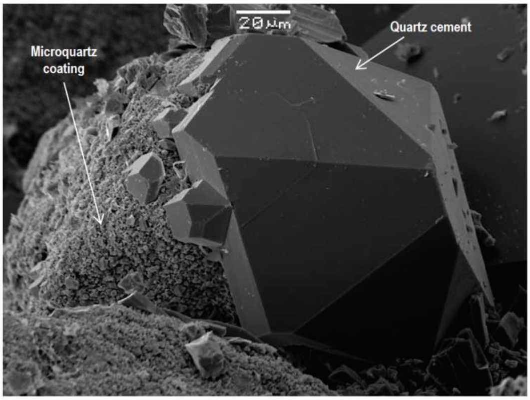
settings influenced by fresh water discharge. The pressence of chlorite ooids suggest suggest that the chlorite coatings are infact a primary depositional features. Such a setting is similar to the Fe-clay facies (Verdine, ooilite ironstone and glaucony facies) described in Odin (1988). Of the Fe-clay facies, the ooilite ironstone alone contain chlorite ooids, and is pherhaps the most feasable analogue. The ooilite ironstone facies is not found on earth today, but the sedimentary record suggest that ooilitic ironstones were widely deposited in central and northern Europe during the Jurassic. The Jurassic chlorite coated sandstones may represent fundamentally the same geochemical conditions, but in a setting of rapid high energy sand influx, as opposed to the current agitated, sand starved, muddy environment of the ironstones. Examples of such settings include the Lower Jurassic Statfjord Formation in the northern North Sea and the Lower Jurassic Tilje-Tofte-Garn Formations of the Haltenbanken region. Chlorite coatings are not common in the Brent Group.

Mg-rich chlorite coatings are less frequent than the Fe-rich chlorite coatings on a global scale. In the arid to semi-arid Permian and Triassic sandstones of the North Sea region however this compositional variety of chlorite coating is dominant, although Fe-rich varieties are also present (Hillier, 1994; Platt, 1993). A review of Petrographic studies carried out on the Permian and Triassic sandstones reveal that grain coating chlorite is commonly found throughout the North Sea region in these sandstones (Hillier, 1994; Hillier et al., 1996; Humphreys et al., 1989; Jeans, 2006; Müller, 1996; Platt, 1993; Purvis, 1989; Sørlie, 1996; Ziegler, 2006). Reportings include fields and discoveries such as Snorre, Draupne, Gannet (Purvis, 1989), Judy and Jade.

Grain coating microquartz

Most of the published literature on microquartz is from the North Sea region where it is common in Upper Jurassic sandstones (Figure 6) of the Morray Firth, Central Graben and South Viking Graben (Hendry and Trewin, 1995; Jahren and Ramm, 2000; Maast et al., 2011; Ramm, 1991; Ramm et al., 1997; Vagle et al., 1994; Aase et al., 1996). Microquartz is also common onshore UK (Haslett, 1992, 1995; Haslett and Robinson, 1992; Wilson, 1968). Onshore UK and in Morray Firth the first appeareance of microquartz seem to be in somewhat older sediments (Bathonian) compared to the Central Graben and South Viking Graben (Oxfordian). It has therefore been proposed that the siliceous sponge Rhaxella, the precursor for microquartz coatings in these sedimets (Hendry and Trewin, 1995), was inhibited from colonizing the South and Central Viking Graben basins until they connected with the Morray Firth sometime during the Oxfordian (Maast et al., 2011). Microquartz is not reported from the northern North Sea/Viking Graben.

Microquartz form from highly silica supersaturated pore waters as opal A and opal CT dissolve. The transformation is a sequentional dissolution-reprecipitation process of opal A to opal CT and opal CT to quartz (Williams et al., 1985). The transformation of silica takes place at relatively shallow burial depths corresponding to temperatures in the range of 35-70 °C (Hendry and Trewin, 1995; Vagle et al., 1994). The fact that microquartz originate from a marine sponge organsim puts some sedimentological and potential facies related constraints on their distribution. For example microquartz coatings will not be present in non-marine sandstones. In certain areas believed to have been sediment starved shoals sponge spicules are the main rock building fabric (i.e. Alness Spiculite Member).



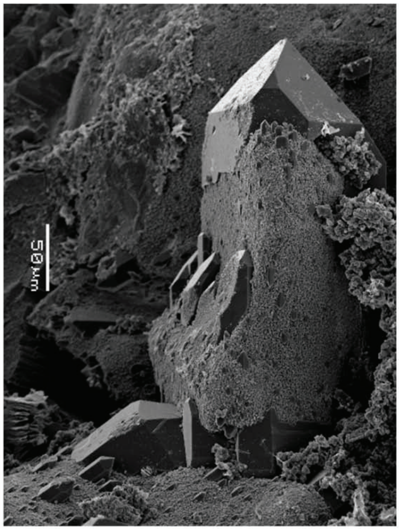


Figure 6. Examples of grain coating microquartz hindering the growth of quartz cement from the Brae Formation.

Early Hydrocarbon emplacement

Whether the presence of hydrocarbon pore fluids will halt quartz cementation and other inorganic chemical processes or not depends on the reservoir wettability. Carbonate reservoirs are preferentially oil-wet and hydrocarbon emplacement may therefore be a success story in such reservoirs (e.g. Scholle, 1977). Sandstones however are preferentially water-wet (Barclay and Worden 2000). This implies that residual water present in a hydrocarbon saturated sandstone cover the grains like a continuous film allowing for continued diffusion and precipitation of quartz (Figure 7). The amount of data supporting continued growth of quartz cement in the presence of hydrocarbons in the North Sea is overwhelming, some of these however do indicate somewhat reduced rates of quartz cementation (Bjørlykke and Egeberg, 1993; Bjørlykke et al., 1992; Bjørlykke et al., 1989; Ehrenberg, 1990; Giles et al., 2000; Giles et al., 1992; Maast et al., 2011; Nedkvitne et al., 1993; Walderhaug, 1990, 1994a; Aase and Walderhaug, 2005). There are still relatively recent claims of the hydrocarbon effect for example from the North Sea Miller field (Marchand et al., 2000; Marchand et al., 2001; Marchand et al., 2002). The Ula trend has also been subject to similar statements (Gluyas, 1997; Gluyas et al., 1993). These hypothesis do however not withstand more rigorous testing (Maast et al., 2011; Nedkvitne et al., 1993; Ramm et al., 1997; Taylor et al., 2010; Aase and Walderhaug, 2005).

Though failing to halt quartz cementation early hydrocarbon emplacement may be of significance for preserving permeability, especially in sandstones exposed to illitisation. Emplacement of hydrocarbons prior to the illitisation of kaolinite and/or smectite may force illite to precipitate in the residual water saturation as pore-lining clays. Thus potentially slowing down quartz cementation indirectly and preserving permeability by inhibiting precipitation of illite in the hydrocarbon saturated portions of the pore-space (Ehrenberg and Boassen, 1993; Thomas, 1986).

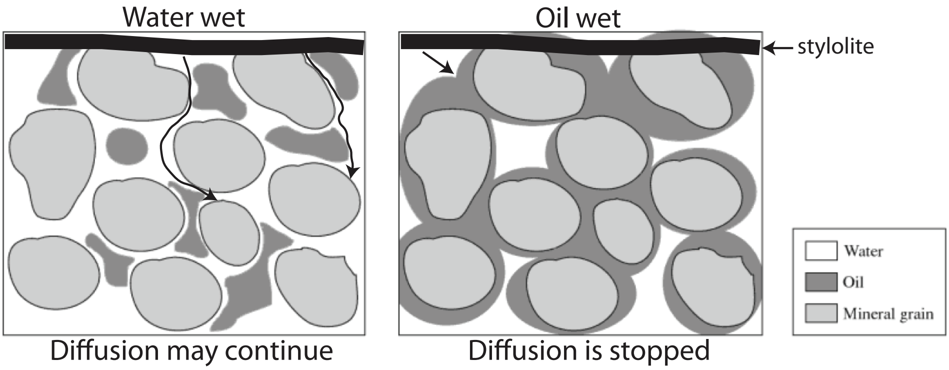


Figure 7. Schematic diagram showing (a) a water-wet reservoir and (b) an oil-wet reservoir. Modified from Barclay and Worden (2000).

Fluid overpressure

Fluid overpressure will reduce the effective stress and thus has the potential to reduce mechanical compaction, if it builds up during shallow burial and persists through time. However overpressure will not affect the quartz cementation process (Bjørkum, 1996). During deep burial in coated reservoirs overpressure will be important in order to reduce the stress at grain contacts and thereby hinder grain fracturing which occur when the effective stress builds up to in excess of about 40MPa (Chuhan et al., 2002). Grain fracturing will expose fresh surfaces for quartz precipitation and rapid quartz cementation will follow.

Modeling sandstone compaction

The concepts reviewed above have resulted in successful reservoir quality predictive tools. State of the art reservoir quality predictive tools are calibrated numerical models that rely on high quality petrographic data and basin modeling reconstructions of the temperature/burial history as input to predict mechanical compaction and quartz cementation (Lander and Walderhaug, 1999; Walderhaug et al., 2000). Mechanical compaction is simulated by substituting the inter granular volume (IGV) for porosity, and introducing a term representing the stable packing configuration of sandstones. The resulting compaction function may be expressed as follows (Lander and Walderhaug, 1999):

$$IGV = IGV_f + (\phi_0 + m_0 - IGV_f)e^{-\beta\sigma_{es}} \qquad \textit{(equation 1)}$$

where IGV is the sum of pore space, cements, and matrix material (volume fraction); IGV_f is the stable packing configuration (volume fraction); ϕ_0 is the depositional porosity (volume fraction); m_0 is the initial proportion of matrix material (volume fraction); β is the exponential rate of IGV decline with effective stress (MPa–1); and σ_{es} is the maximum effective stress (MPa). Experimental compaction of sand aggregates has resulted in empirical equations that probably represent more accurate simulations of compaction by incorporating sandstone texture into the equation (Fawad et al., 2010):

$$IGV = 0{,}4807 - 0{,}0023\sigma_e - 0{,}1060\alpha - 0{,}0098\beta - 0{,}0812\gamma + 0{,}0079\delta \qquad \textit{(equation 2)}$$

where IGV is a function of the effective stress σ_e (MPa), α is the grain size (mm), β is the grain shape (fraction), γ is the sorting (phi scale) and δ is the quartz percentage (fraction).

The essential elements of the quartz cementation model are the kinetics of quartz precipitation and the surface area available for quartz cement growth. The rate of quartz cementation per unit of surface area has been shown empirically to be a function of temperature (Walderhaug, 1994a):

$$r = a10^{(bT)} \qquad \textit{(equation 3)}$$

where a is the quartz precipitation rate preexponential constant (mol/cm^2 s), b is the quartz precipitation rate exponential constant (°C^{-1}), and T is temperature (°C).

This function can be extended to calculate the total amount of quartz cement precipitated during an increment in time by taking into account the surface area available in the sandstone for precipitation of quartz cement, and by considering the temperature exposure through time experienced by the given volume of sandstone (Walderhaug, 1996)

$$qcv = \frac{m}{\rho} Aa \int_{0}^{t} 10^{b(c_n t + d_n)} dt \qquad \textit{(equation 4)}$$

where qcv is the volume of quartz that precipitates (cm^3), m is the molar weight of quartz (60.08 g/mol), r is the density of quartz (2.65 g/cm^3), A is the quartz surface area (cm^2), t is the duration of the time step (m.y.) converted to seconds, a is the quartz precipitation rate preexponential constant (mol/cm2 s), b is the quartz precipitation rate exponential constant (1/°C), and c_n and d_n are constants for each time step n (derived from the sample's temperature history).

The quartz surface area plays an important role in controlling the net rate of quartz cementation, as shown in equation 4. The simplest way to calculate the quartz surface area is to assume that the grains are spherical and that the grain to grain contact area is equal to the increased surface area caused by irregularities in the grain shape. In such a case the quartz surface area will be a function of the abundance of detrital quartz grains in the initial sediment, the average quartz grain size, and the porosity through time (Walderhaug, 1996):

$$A = (1 - coat)\left[\frac{6qgf_0 v_0}{D}\left(\frac{\phi}{\phi_0}\right)\right] \qquad \textit{(equation 5)}$$

where A is the quartz surface area for the present time step (cm^2), qgf_0 is the amount of quartz grains in the initial sediment (fraction), v_0 is the initial rock volume (cm^3), D is the average diameter of initial quartz grains (cm), ϕ is the porosity for the present time step (fraction), ϕ_0 is the initial porosity (fraction), and $coat$ is the quartz surface area that is coated and thus unable to act as a substrate for further quartz precipitation (fraction).

Further modifications of these algorithms should be made to account for quartz cementation following grain fracturing in coated reservoirs. Models for illitisation of kaolinite and feldspar dissolution are now available (Lander and Bonnell, 2010). Recently Lander et al. (2008) has pointed out the tendency of the algorithm to overpredict the amount of quartz cement in fine-grained sandstones. These errors were demostrated to be caused by the transition from non-euhedral to euhedral crystal growth (Figure 8). Euhedral crystals are formed more rapidly on smaller grains.

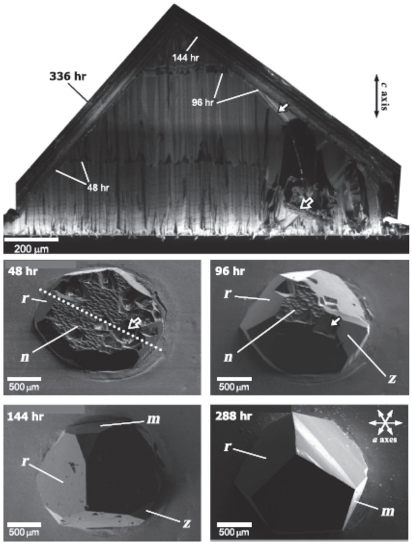


Figure 8. Morphology and texture of a quartz overgrowth from the experiments of Lander et al. (2008). Note the significant decrease in growthrate after an euhedral crystal form has developed.

Main findings

This section summarizes and gives a brief overview of the main findings and conclusions of papers 1 – 4 and extended abstract 1.

Paper 1:

The impact of quartz and illite cementation on deep reservoir quality in Upper Jurassic, syn-rift sandstones of the Central Graben, North Sea *(submitted to AAPG Bulletin)*

This paper document regional variations in reservoir quality within the Late Jurassic Ula and Heno Formations, located respectively in the Cod Terrace and Feda Graben region of the Central Graben. The Ula Formation contain large variations in reservoir quality that are caused by variable amounts of quartz cement due to grain coating microquartz preserving porosity in specific sequences. The Heno Formation show porosities comparable to the high porosity microquartz coated sandstones within the Ula Formation, despite burial depths in the range 4500 – 5500 meters (vertical depth below seafloor). Permeabilites are however variable and linked to facies. High permebilities (>10 mD) are evident in shoreface facies within the Gert Member, whereas permeabilities are poor (<1 mD) in backbarrier facies within the Gert Member and in the Ravn Member. The main purpose of the paper was to investigate the deeply buried Heno Formation and compare the diagenetic controls on reservoir quality to the Ula Formation.

Main findings and conclusions:

- Petrographic analysis of well 1/3-9S (Tambar field) confirm the importance of quartz cementation and porosity preserving effect of microquartz coatings in the Ula Formation.
- Quartz cement content is low to moderate relative to depth / temperature in the Heno Formation. Authigenic illite exert a more important control on reservoir quality in these sandstones.
- High permeability and porosity is preserved in shoreface facies within the Gert Member due to pore-lining illite. Poor permeability is caused by abundant pore-filling illite.
- Despite large variations in permeability, the porosity can be fairly constant due to the highly porous nature of authigenic illite.

Paper 2:

Diagenetic controls on reservoir quality in Middle- to Upper Jurassic sandstones in the South Viking Graben, North Sea *(AAPG Bulletin)*

The paper document variations in sandstone reservoir quality in Middle- to Upper Jurassic sandstones in the South Viking Graben province, and document that these variations are caused primarily by variations in the amount of quartz cement. A simplified subdivision based on reservoir quality relative to average depth trends gave three categories, high- normal- and low porosity sandstones.

Main findings and conclusions:

- High porosity sandstones were shown to be linked to the pressence of grain coating microquartz. Low porosity sandstones have proposedly been subject to elevated temperature exposure due to higher geothermal gradients at transfer faults and basement highs. Normal porosity sandstones represent the average porosity depth trend in sandstones that have not been subject to elevated temperature exposure or grain coating microquartz.

- This study is the first attempt to document the stratigraphic and geographic distribution of microquartz coatings. Microquartz was found to be constrained to Oxfordian – Tithonian sequences and geographically to the Vilje Subbasin and likely Ve Subbasin. It is well known that microquartz coatings originate from the transformation of Rhaxellid sponge organisms during shallow burial. Proposedly Rhaxellid sponges colonized the South Viking Graben from the south during the Oxfordian, when the Viking Graben, Central Graben, and Moray Firth became connected marine basins.

Paper 3:

Sedimentology, mineralogy and diagenesis of the Draupne discovery: Implications for reservoir quality prediction and the formation of grain coating chlorite in the Triassic Skagerrak Formation *(manuscript)*

The 2009 Draupne discovery provided the opportunity to study core material from the Triassic Skagerrak Formation and Jurassic Sleipner Formation buried to about 2,5 km depth. The Skagerrak Formation contain chlorite coated sandstones that preserve porosity at greater burial depth. In this study sedimentological and petrographic studies were carried out, resulting in a model for the generation of chlorite coatings that may be important for future Skagerrak Formation exploration targets in the more deeply buried Central Graben. In addition the contrasting mineralogy and diagenesis of the Jurassic and Triassic sandstones related to climate were pointed out.

Main findings and conclusions:

- The Triassic Skagerrak Formation is compositionally less mature than the Jurassic Sleipner Formation. Kaolinite is the principal clay mineral of the Jurassic sandstones whereas Smectite, illite and chlorite dominate the Triassic sandstones. These mineralogical differences are related to the transition from a arid to semi arid climate during the Triassic to a humid climate during the Mid to Late Jurassic.
- Chlorite coatings form mainly in the distal portions of Triassic terminal fan sequences (terminal splay or sandflat facies association). It is proposed that waning flow cause infiltration of detrital smectite that attach to grain surfaces in the vadose zone and act as precursors for growth of chlorite coatings.

Paper 4:

Changes in physical properties of a reservoir sandstone as a function of burial depth – The Etive Formation, northern North Sea *(Marine and Petroleum Geology)*

This paper presents a detailed investigation of how the compaction trend of a relatively homogeneous lithology varies with depth and temperature. The shallow marine Etive Formation of Middle Jurassic age from the northern Viking Graben was chosen for this purpose. In the study area the Etive Formation is buried from 1600-4000 meter below sea floor which enabled us to study the effect of burial diagenesis on rock properties. The Etive Formation sandstones are beach/barrier deposits and consist mainly of well sorted, medium sized, sand. Petrophysical properties from 21 wells were analyzed and compared with experimental compaction of loose Etive sand together with petrographical analysis of 23 thin sections. Reservoir characterization, basin modeling and quantitative seismic interpretation require information about how rock physical properties change with depth This study, which combines well log data with experimental compaction and petrographic analysis provide important information on the dependency on various diagenetic processes on rock properties in sandstones.

Main findings and conclusions:

- In a single, well defined lithology such as the Etive Formation the velocity and density always increase with increasing burial depth and temperature.
- At burial depths corresponding to temperatures lower than 70-80 ºC (<2000-2500 m in the northern North Sea) there is a good agreement between velocities, densities and porosities derived from well logs and values found by experimental compaction. This indicates that the vertical effective stress generated by the weight of the overlying sediments is the main porosity reducing agent at shallow depth.
- From about 2000 meters (>70ºC) there is a break in the velocity-depth gradient that may represent the onset of chemical compaction, mainly by quartz cementation, as observed by the petrographic analysis. This relatively marked increase in velocities without a corresponding increase in densities. An explanation for this may be that only a small amount of quartz cement, which will not cause a marked volume reduction, may have the potential to stiffen the rock framework, thus increasing the velocities.

- From the onset of chemical compaction there is a strong correlation between petrophysical properties and the amounts of quartz cement found by the petrographic analysis. This strong dependency of quartz cement on velocities and densities, and the fact that these properties deviates from the experimental compaction curves at burial depths greater than 2000 meters, indicate that the compaction is a function of temperature insensitive to the effective stress after the onset of chemical compaction. Furthermore, the petrographic analysis showed no evidence of a reduction in intergranular volume after the onset of chemical compaction, which indicates that the source of silica is from dissolution at stylolites.

Extended Abstract 1:
Is grain-to-grain pressure solution contributing to quartz cementation in sandstones?
(75th EAGE Conference, 2013, London, UK)

Petrographic investigations of the Precambrian orthoquartzitic Hanglecærro Formation from the Varanger Peninsula was undertaken in this study in order to investigate compaction processes in a completely cemented and essentially pure quartz arenitic sandstone. The current scientific consensus do not regard grain-to-grain pressure solution to be a significant source of quartz cement, but regards quartz cementation as sourced from stylolites and clay laminae. The overall process usually beeing limited by temperature (the precipitation rate of quartz) and insensitive to pressure (effective stress). However it has been shown that in unusually clean sandstones when stylolite distance increase to more than a few decimeters quartz cementation will become diffusion controlled. We wanted to investigate whether grain-to-grain pressure solution could be taking place in essentially clay free quartz arenites.

Main findings and conclusions:

- Intergranular volumes showed that grain-to-grain pressure solution could not have been the source of quartz cement in the investigated samples and therefore provides further evidence supporting quartz cementation as sourced primarily from stylolites and clay laminae.
- There was observed a distinct relationship between the inter granular volume and grain texture, especially sorting. Moderately sorted samples were more compacted

than well sorted samples. This is consistent with experimental compaction of sand aggregates.

- Reservoir quality predictive tools generally simulate mechanical compaction as a function of depth or effective stress. This does not account for the large variations seen in the intergranular volume (and porosity) of sandstone sequences in nature. Simulation of mechanical compaction can therefore be improved by incorporating empirical equations from experimental compaction experiments that account for grain texture as well as the effective stress.

Concluding remarks

This study shows that viewing sandstones as geochemically closed systems enables reservoir quality to be predicted as a function of initial sediment composition and texture, which is related to the depositional setting (facies, provenance, climate), and compaction processes. The reservoir properties in sandstones at shallow depth will mainly be a function of the sorting, grain size, clay content and mineralogy. These variables will govern the rate of mechanical compaction during shallow burial. In deeply buried sandstones (> 4km) reservoir properties will deplete rapidly due to quartz cementation and illitisation of kaolinite. The degree of quartz cementation will be a function of the quartz surface area available for cementation and the exponential increase in the precipitation rate of quartz with increasing temperature. Clay mineral transformations may significantly reduce the permeability, as is the case for illitisation of kaolinite. In deeply buried sandstones grain coatings are important in order to inhibit quartz cementation and preserve porosity. Over pressure and hydrocarbon emplacement does usually not inhibit quartz cementation and therefore do not preserve porosity in deeply buried sandstones. Over pressure will however reduce the effective stress and may therefore inhibit grain fracturing which will lead to quartz cementation in coated reservoirs. Hydrocarbon emplacement may preserve permeability if the charge of hydrocarbons takes place prior to illitisation of kaolinite. In such a case illite will tend to precipitate as pore-lining clays in the residual water saturation preserving permeability.

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Enclosures

3

Ext. Abs. 1

Th-09-11

Is Grain-to-grain Pressure Solution Contributing to Quartz Cementation in Sandstones?

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SUMMARY

The role of grain to grain pressure dissolution versus dissolution at stylolite or clay induced dissolution (CID) of silica in quartz rich sandstones is evaluated from careful examination of samples from the Precambrian Hanglecærro Formation located on the Varanger Peninsula in northernmost Norway. The Hanglecærro Formation is an orthoquartzite where all porosity is gone leaving an end product suitable for studying compaction processes in detail. The study show that the intragranular volume (IGV) in all samples is above what would be expected from grain to grain dissolution confirming that this mechanism is not important in siliciclastic sandstones. The variability in IGV was found to be a function of textural parameters where sorting was found to be the main factor reducing IGV. Textural parameters are important only during mechanical compaction. During chemical compaction IGV will remain constant. Empirical equations that predict the IGV as a function of effective stress and textural parameters should be incorporated into state-of-the-art reservoir quality predictive tools in order to more accurately predict mechanical compaction, and the expected porosity range in any given sandstone.

Introduction

Recent attention has been given to state-of-the-art reservoir quality prediction and the main principles that these models rely upon (Ajdukiewicz and Lander, 2010; Taylor et al., 2010). Porosity is lost by stress sensitive mechanical compaction processes during shallow burial and temperature sensitive chemical compaction at greater depths (Bjørlykke, 2003). Chemical compaction is dominantly by quartz cementation which can be accurately predicted as a function of the temperature exposure over time (Walderhaug, 1994; Walderhaug, 1996, 2000). Quartz cement is thougth to be internally and locally sourced from dissolution along stylolites (Oelkers et al., 2000). Silica is transported by diffusion into the interstylolite region where precipitation takes place. Precipitation is the rate limiting step in most cases. The overall process is often refered to as clay induced dissolution (CID). Grain-to-grain pressure solution (i.e. Sheldon et al., 2003) is thougth to be insignificant as source of quartz cement (Bjørkum, 1996). In exceptionally clean sandstones it has been shown that quartz cement abundance decrease away from stylolites when the distance to nearest stylolite increase to more than a few decimeters (Walderhaug and Bjørkum, 2003). This might suggest that quartz cementation could be more succesible to grain-to-grain pressure solution in such sandstones. One would expect a gradual decrease of the inter granular volume (IGV) if grain-to-grain pressure solution in fact is a source of quartz cement in sandstones (Ramm, 1992; Rittenhouse, 1971). In the opposite case, namely that of diffusive transport of silica from stylolites (CID), one would expect IGV values in interstylolite sandstones to be more or less identical to those at the onset of cementation. In the current study Precambrian quartzite samples from the Varanger Peninsula are investigated petrographically with respect to quartz cement volume and inter granular volume especially. The aim was to test the hypothesis that grain-to-grain pressure solution might be a significant contributor to quartz cement in sandstones essentially devoid of clay and consequently not subject to intense CID/stylolitisation.

Geological setting

The sample database consists of compositionally and thermally mature sandstones from the Precambrian Hanglecærro Formation located on the Varanger Peninsula. The original quartz sand of this Formation was derived from a strongly weathered land surface (Siedlecka and Lyubtsov, 1997), deposited in a wave dominated, shallow marine environment (Johnson et al., 1978) in terminal Riphean time (Siedlecka and Roberts, 1992; Sturt et al., 1975). Endured marine reworking caused the sandstones to become compositionally mature quartz arenites. What little feldspar that was present in these sands was mostly transformed to kaolinite during meteoric freshwater flushing. Most of the flushed sands where later reworked and redeposited leaving only quartz. Quartzites with a clay content above about 1% represents units not reworked after water flushing. The fact that kaolinite has been directly transformed to pyrophyllite (Fjellanger and Nystuen, 2007) and not illite during deep burial diagenesis reflect that no feldspar remained in the sandstones after water flushing. The Hanglecærro Formation has been subject to atleast two episodes of burial and uplift and is presently exposed on the Hanglecærro ridge (Figure 1).

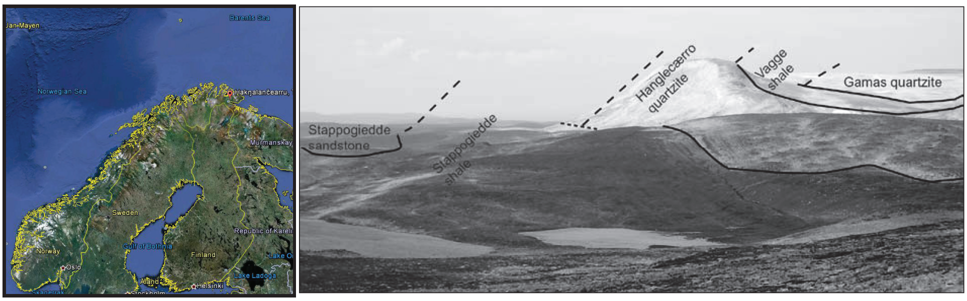

***Figure 1** Sample location of the Hanglecærro Formation.*

Methods and Petrographic results

21 samples were subject to standard point-count analysis. Grain-size and sorting were estimated from measuring the long axis (a-axis) of 50 randomly selected grains from each sample. Grain-size measurements are presented as arithmetic mean and sorting as the standard deviation of these measurements. The samples are nearly pure orthoquartiztes, dominantly consisting of quartz grains and overgrowths (Figure 2). Distinguishing between quartz grains and cement was straight forward in the analysed samples due to visible dust rims. Quartz grains are mostly monocrystalline, but polycrystalline grains make up a minor portion of the samples. All the original pore-space has been filled in with cement. In addition to quartz cement, a few samples contain authigenic clays mainly pyrophyllite but some unaltered kaolinite still remains in some samples. The pyrophyllite is most likely a transformation product of kaolinite (Fjellanger and Nystuen, 2007). The coexistence of kaolinite and pyrophyllite indicate a maximum burial temperature of around 270^{o}C (Hemley et al., 1980) . The samples are homogenous in terms of texture and are mostly medium grained and moderately to well sorted (Figure 2). Quartz cement is volumetrically important and make up from 12 – 30 % of the bulk samples.

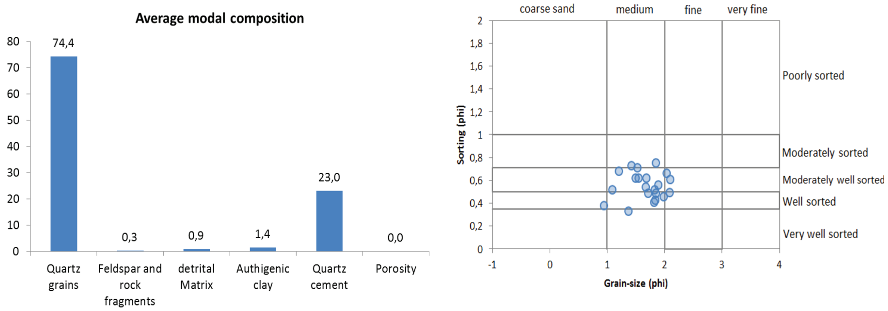

Figure 2 *Modal composition and textural parameters of the samples from the Hanglecærro Formation.*

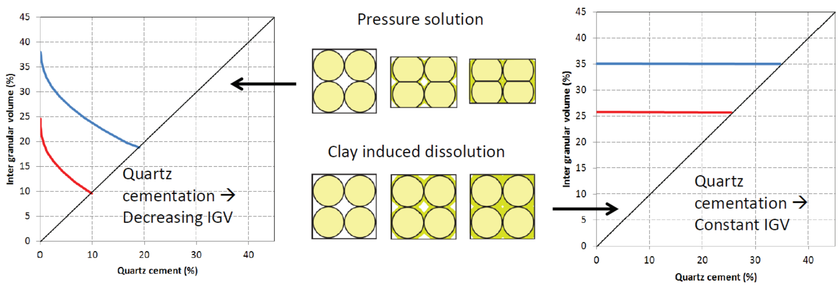

Figure 3 *Theorethical IGV development during grain to grain pressure solution (a) and CID/stylolites (b) respectively (curves based on Rittenhouse 1971).*

Discussion

Whether grain-to-grain pressure solution is a significant contributor to quartz cement in sandstones can be derived from the IGV. Rittenhouse (1971) and others have shown how the intergranular volume will decrease with cementation in the case of grain-to-grain pressure solution (Figure 3a). In the case of CID the interstylolite porespace will be passively infilled with cement leaving the IGV unchanged as cementation commences (Figure 3b). The analysed samples show intergranular volumes in the range of 20 – 30%. Two subpopulations may be identified. “High IGV” samples plot between cubic close packing (CCP) and random cubic packing (RCP) of equal spheres (between 25,9% and about 36% IGV), whereas "low IGV" samples plot below CCP (Figure 4a). As the models of Rittenhouse and others clearly illustrate, the IGV values are to high for significant grain-to-grain pressure solution to have taken place in the Hanglecærro Formation. The scatter of the IGV data is related to textural parameters. "High IGV" samples are well sorted whereas "low IGV" samples are moderately to moderately well sorted (Figure 4b). The effect of texture on mechanical compaction is often understated in reservoir quality prediction. Typically simple IGV vs depth/stress curves are used (Lander & Wald, 99; Paxton 2002).

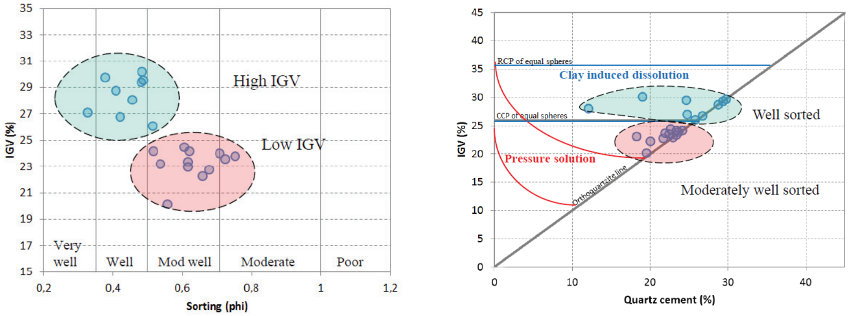

Figure 4 *IGV populations (a) and the relation to textural parameters and theoretical IGV development (b) from the Hanglecærro Formation. The data indicates the CID mechanism.*

Experimental compaction of sand aggregates show the effect of texture on mechanical compaction (Chuhan et al., 2002; Fawad et al., 2010). Coarse grained sands have fewer grain contacts per unit area and therefore distribute stress less efficiently than fine grained sands. Coarse sands therefore compact more rapidly than fine grained sands. Poorly sorted sands will have significantly lower depositional porosity than well sorted sands. Fawad et al. (2010) came up with an empirical equation where porosity in experimentally compacted sand aggregates were predicted as a function of stress, grain-size, grain shape, grain sorting and the quartz percentage:

$$\Phi = 0{,}4807 - 0{,}0023\sigma_e - 0{,}1060\alpha - 0{,}0098\beta - 0{,}0812\gamma + 0{,}0079\delta \qquad (1)$$

where φ is porosity (fraction) calculated at an effective stress σ_e (MPa), α is the grain size (mm), β is the grain shape (fraction), γ is the sorting (phi scale) and δ is the quartz percentage (fraction). Such an equation should be incorporated into reservoir quality predictive algorithmns in order to obtain more accurate simulations of mechanical compaction. In the chemical compaction regime there is growing evidence that the IGV will remain constant during quartz cementation. This supports the CID/stylolites models. In a sandstone sequence the IGV (and porosity) will always vary greatly around the average (10% variation is commonly seen). These variations probably reflect the range of textural parameters present in the sandstones. Incorporating equations such as equation 1 will therefore give more accurate predictions not only of the average porosity, but also for the expected porosity range for given textural parameters.

Summary

The Hanglecærro orthoquartzites show no evidence of grain-to-grain pressure solution. Two IGV clusters were recognized. The High IGV (CCP-RCP) represent well sorted samples, whereas low IGV (IGV<CCP) represent moderately to moderately well sorted samples. The study illustrates the importance of incorporating the textural control on mechanical compaction. There are empirical equations that predict the IGV as a function of effective stress and textural parameters (i.e. Fawad et al. 2010). These should be incorporated into state-of-the-art reservoir quality predictive tools (i.e. Lander and Walderhaug, 1999) in order to more accurately predict mechanical compaction, and the expected porosity range in a given sandstone.

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Ext. Abs. 2

The Stirby prospect – a new look at the deep Jurassic in the South Viking Graben

Introduction

Exploration normally proceeds in distinct phases. A new phase produces new drilling results which create a new trend if they are positive. If the results are negative exploration can stagnate until a new phase is begun. A new phase is often initiated by changed market conditions, a new technology, or a new discovery in an adjacent related basin. Traditionally structural traps are drilled first, followed by stratigraphic traps, and finally “hidden traps”. New initiatives in “tired” basins require imagination, dedicated technical work, and most of all freedom from the entrenched prejudices which terminated the previous exploration phase. The Stirby prospect is a deep HTHP prospect identified in the southwest of the Norwegian block 24/12. There are two main potential reservoir intervals, denoted Stirby Deep and Stirby Upper. The basic structure is a down-faulted 3-way dip closure which is similar to the Gudrun Field.

Exploration History

The Southern Viking Graben began to be an interesting exploration area in 1971 with the discovery of the Sleipner field, followed by the Gudrun and North Brae Fields in 1975. The latter involved deep Jurassic reservoirs which showed some considerable quartz cementation with depth. The trend was followed northwards with 15/3-2 (1977), and 24/12-1R (1978). These wells proved hydrocarbons, but reservoir parameters were virtually absent due to pervasive cementation. The search for hydrocarbons in the Jurassic in the Norwegian sector of the Southern Viking Graben entered a passive phase after these wells and this was generally confirmed in 1996 by the 25/10-6 well which suffered the same negative result.

Regional Geology

The Southern Viking Graben is normally considered as a classic westerly dipping half graben with a major fault to the west forming the boundary with the adjacent East Shetland Platform to the west. The dominant north-south faulting trend is inherited from the Triassic. The major fault movements are of Late Jurassic age and superimpose a NNE-SSW trend on the older faults giving an en-echelon appearance to the graben boundaries. A period of uplift and erosion in early Jurassic times was followed by a regional transgression depositing first fluvial then shallow marine sand-prone reservoir sequences of the Sleipner and Hugin Formations, followed by marine shales of the Heather and Draupne Formations. A large variety of late Jurassic sand influxes occurred as point input turbiditic flows from the west during the Late Jurassic, giving rise among others to the various Brae

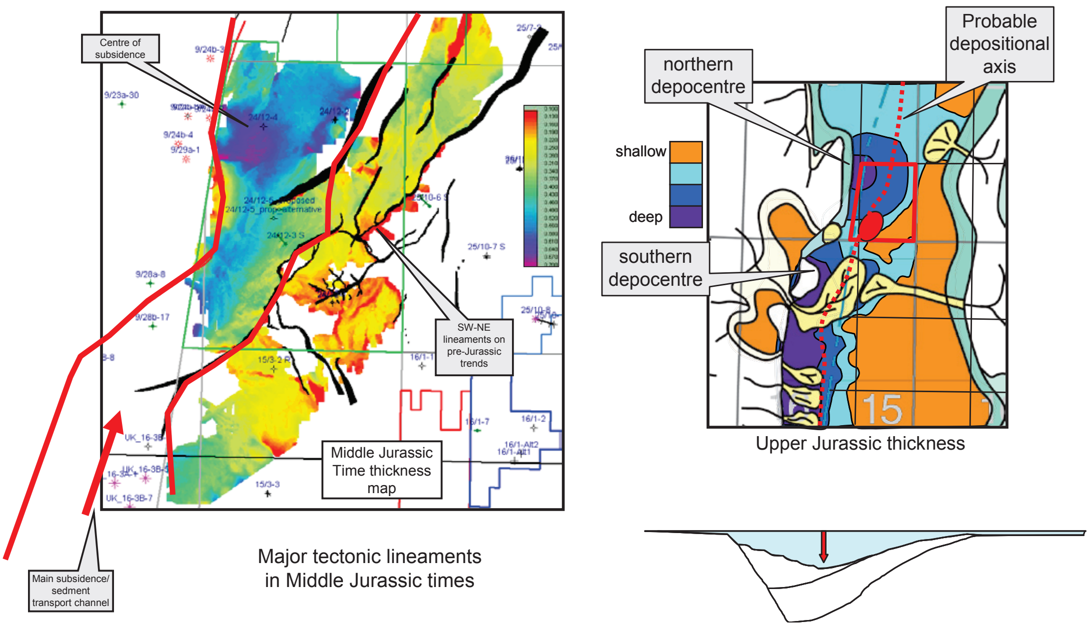


Figure 1. Depositional model of the Brae Formation.

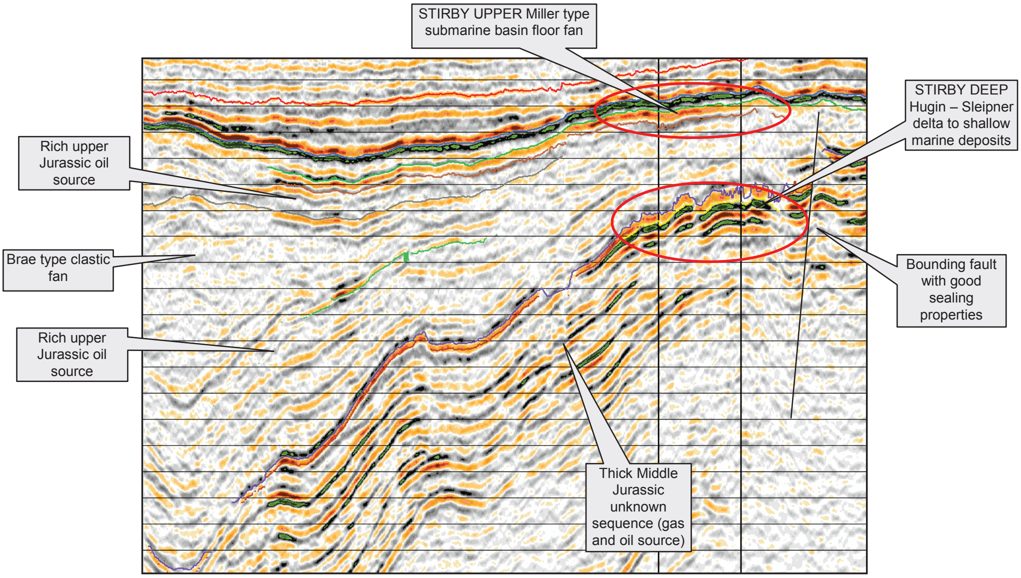


Figure 2. Illustration of the prospect and play model.

sand reservoirs in the south of the area. These sands are less explored in the north, and are not expected north of the Devenick field where the Crawford embayment terminates the main Graben fault. The sand input generally ceases in end Mid Volgian times and the latest Jurassic sediments comprise the organic rich shales of the Draupne Formation. A more limited sand influx is interpreted from the east, primarily using the well data from the Gudrun field, though the lack of an extensive hinterland prohibits large volumes of sand from this direction.

To fully understand the geological history the regional geology from both UK and Norwegian areas must be integrated. A new regional study of the area using 3D seismic and all available wells reveals that in Middle Jurassic times the main graben subsidence was confined to a reasonably symmetrical graben which was at its narrowest in the area of the Stirby prospect in the south west corner of the block 24/12. At this point a major fault trend, which forms the main eastern graben boundary 40km to the northeast at the Balder field, cuts across the graben to the southwest before dying out at the Norwegian/UK border. This fault in the area of interest forms the boundary between a central graben with thick Middle Jurassic sediments, and an easterly flanking terrace with thinner deposits of the same age. In Upper Jurassic times the Graben became asymmetrical, largely due to the sediment loading effect from a series of sands of various ages and input points, derived from the uplift and erosion of the East Shetland Platform to the west. These sand input episodes largely ceased at the end of the Mid Volgian when deposition of organic rich shales of the Draupne Fm. continued for the remainder of the Jurassic.

The Stirby prospect Identification

The Stirby prospect is a potential multi-pay structure, which is best seen at Middle Jurassic levels where a thick parallel high energy seismic package representing the Hugin and Sleipner Formations dips to the northwest away from the margin fault which forms the seal for the trap. Above this the Upper Jurassic sequences are found in a small 4-way dip closure on the downthrown side of the margin fault in a manner which is almost a copy of the Gudrun Field 20 km to the south. This structure is obvious, also on older 2D seismic data. It has been recognised since 1975, but it has not been drilled due to the above mentioned experience from wells in the area that reservoirs at this depth are completely cemented, and no longer represent a viable reservoir. In addition the prospect is deep and a well will be expensive. The subject of this article is to demonstrate how these old prejudices have been challenged, and the prospect is now elevated into a highly graded exploration prospect due for drilling in 2010. Although Stirby is a multi-pay prospect we will discuss only the upper level in this article.

Prospect analysis

There is no shortage of oil in the area and the three most relevant wells, although highly cemented, showed extensive hydrocarbon saturation. The structural outline of the trap is well defined and seal to the east is thought to be formed by the pinch-out of the sand as mapped on the seismic data. The fault to the east is a major syn-sedimentary fault which can be expected to have steered the sand pinch-out. The expected high overpressure is also a favourable sign for sealing potential. The bulk of the uncertainty around the Stirby prospect lay initially with the risk for a cemented non-viable reservoir.

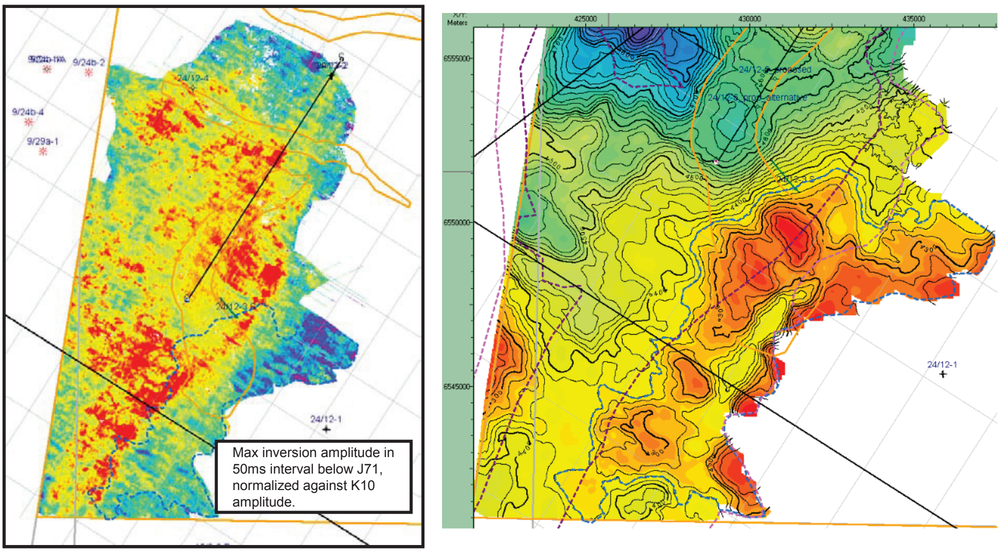
The present prospect analysis started with the observation that porosity with depth in this area is highly variable, and that it is dependant on the sedimentology of the reservoir. The main initial risk was primarily the quartz diagenesis which has been the focus of considerable study and discussion in the literature. There is general agreement that temperature is the main controlling factor, normally causing tight reservoirs at temperatures over 120°C (Bjørlykke and Egeberg, 1993). However the formation of a microcrystalline quartz coating has been shown to inhibit the increase of quartz cementation with depth (Aase et al., 1996). Micro-quartz coatings are common in the North Sea Upper Jurassic and are found in the East Brae Field (Leishman, 1994) useful porosity is preserved despite temperatures up to 140°C.

A second observation was that none of the wells in the area directly test the reservoir sands for the Stirby Upper trap. To address these doubts the depositional picture had to be extracted from the seismic data in addition to the structural framework. From the detailed interpretation of reprocessed 3D seismic data an amplitude brightening in the seismic immediately below the strong Base Cretaceous event was noticed. To enable a better interpretation, the data was inverted and the event mapped at the top and base of an apparent higher impedance interval. This interval showed an interesting amplitude pattern which was not coincident with the structural closure. Since its form was marred by the masking effects of a series of shallow channels at the seabed, the amplitude map was normalized with the assumption of a constant impedance contrast at the base Cretaceous event.

The result showed a convincing geometry such as we should expect from a classic basin floor fan.

However the geometry indicated that this was sourced from the SSW, rather from the west as might be expected. The available seismic data to the south was studied but proved too poor to follow the feature directly in the up-flow direction. Analogies to the nearby Miller field and the porosity development of the sands in the Brae area came to mind, prompting a study of a data from this area.

A good deal of highly relevant observations made through the many production wells in the Brae area - specifically East Brae, allowed a positive link of the fan back directly to the East Brae Field (Brehm, 2003). The well data show that the sands are highly channelized, becoming rapidly non-reservoir away from the channel axis. In addition the sands are highly constrained by topography, and can be shown to be deflected round positive local relief, and along the downthrown side of local faults. The channel comprising the East Brae Field



J71norm = $J71_{(inv\ amp)}$ - $1.4xK10_{(fulloffset\ amp)}/50$ +600

Figure 3. Outline of the amplitude anomaly resembling a submarine fan (left) and map of top reservoir (right)

is mapped exiting the East Brae area in a direction towards the NNE - directly in line with the interpreted feeder channel of the Stirby Upper sand.

There are no wells drilled in the mapped Stirby Upper fan, but the well 24/12-2T2 well is drilled just north of the pinch-out and can be directly tied to the seismic of the Stirby Fan. The dating of the relevant interval in this well coincides with the dating of the uppermost of the two main sands in the East Brae Field (J71-J73), further enhancing the interpretation that the two sands are the same. This well also confirms that the sands pinch-out at the margins of the fan though the cuttings descriptions note an increase of sand content in the relevant interval. Furthermore the paleo-topography interpreted from the data predicted a threshold at the southern edge of the Stirby prospect, north of which the subsidence, and hence depositional accommodation space was greater. This supports the scenario of a submarine channel flowing across the shelf from the south, spreading out to a fan north of the threshold.

Besides the main depth dependency of the diagenesis in the area, the sedimentary facies are recognised to be an important additional factor. The doubts concerning the porosity in the prospect could now be addressed using data from several wells in the East Brae field in the same sand. One of these wells (UK 16/3-9) tested the sand deeper than in the Stirby Upper prospect, but still with useful porosity.

Risk analysis & Development options

The exploration risk for the Stirby prospect is typical of most modern prospects in the North Sea and is entirely dependant on what is being risked. Traditional exploration risk concerns itself with an estimate of the probability of a functioning hydrocarbon system – a yes/no question. Increasingly in mature areas the question becomes “how much” and is very much a sliding scale, demanding a different approach to the risking process. From the work done we believe the probability of trap, seal, source and sand presence is high. There is a very high probability of some hydrocarbons (a discovery), but the probability of a viable reservoir is lower. The scenarios run so far indicate a wide range of possible outcomes, with total resources ranging from 17 to 171 MSm^3OE. These cannot be assessed using a single development concept, and hence will have several thresholds of commerciality depending on the development option chosen. The main uncertainties in the Stirby prospect are now the performance of the reservoir which dictates the number of wells required for a development. The probability of commercial success depends on the assumptions made in the development concepts - since drilling wells will be expensive. If the average porosity range is between 12 and 13%, with an absolute range of between 6 and 18%, the number of wells required will depend on the permeability, the arrangement of the better porosity zones, and even on whether the production wells are completed with hydraulic fracturing. On the other hand since the reservoir fluid is gas/condensate, we expect to be able to produce commercially from much lower average porosities if they should prove to be present.

Conclusion

The Stirby prospect illustrates that old prejudices in mature basins must be constantly challenged in the light of new knowledge, new techniques, and new data. These are linked to the most essential components in our future exploration: attention to detail, critical thinking, and uncertainty management.

Thanks are due to the partners in the licence PL341, and specifically to O.R.Heum for his support in the process of challenging established "truths".

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Numerical modeling including hysteresis properties for CO_2 storage in Tubåen formation, Snøhvit field, Barents Sea.

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Abstract

In April 2008 the first injection of supercritical CO_2 started into the Tubåen Formation from the Snøhvit field, Barents Sea. At full capacity, the plan is to inject approximately 23 Mtons of CO_2 via one well during a 30 year period. The aim of this study was to simulation the 30 years of injection of supercritical CO_2 and the following long term (5000 years) storage of CO_2 in the Tubåen formation. The formation is at approximately 2600 meters depth and is at 98ºC and 265 bars. The simulations suggested that, because of limited lateral permeability, the bottom hole pressure increases rapidly to more than 800 bars if an annual injection rate of 766000 tons is used. This is significantly higher than the fracture pressures for the formation, and it is therefore suggested that the aim to inject 23 Mtons over the planed 30 years may be unrealistic. To prevent fracturing due to increasing pressure, the bottom hole pressure constraint is applied that leads to significant decrease in the amount of CO_2 injected. With the hysteresis property applied, reservoir pressure behavior is the same in the base case (no hysteresis); however, the CO_2 plume is distributed over a smaller area than in the base case. Similar to the case of hysteresis, the diffusion flow case shows the CO_2 plume to be distributed over a smaller area than in the base case, but reservoir pressure decreases more than in the other two cases.

Keywords: CO2 storage; compositional simulation; residual trapping; solution traping; hysteresis.

1. Introduction

Underground sequestration of carbon dioxide is a viable greenhouse gas mitigation option by reducing the release rate of CO_2 to the atmosphere [1]. CO_2 injected underground can be trapped in reservoirs by four storage mechanisms: (1) structural and stratigraphic trapping; (2) residual CO_2 trapping; (3) solubility trapping; and (4) mineral trapping [2]. In the shorter time frame, the three mechanisms: structural, residual and dissolution trapping, dominates the CO_2 storage. These mechanisms are therefore very important and must be represented correctly in numerical simulations. In April 2008 Statoil started injecting CO_2 into the

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Tubåen Formation at a depth of approximately 2600 meters. The gas was captured from the Snøhvit gas field in the Barents Sea. Previously, the long term behavior and distribution pattern of CO_2 in the reservoir has been investigated by geological modeling with a maximum time frame of 1000 year [5, 6]. Several experiments were performed to investigate surface tension, capillary force and relative permeability relationships for supercritical CO_2 and brine [7]. The effects of hysteresis in relative permeability functions were investigated and residual trapping was shown to significantly prevent movement of CO_2 upward [8, 9]. One long term simulation in Snøhvit was performed to investigate the CO_2 migration pathways and sealing capacity of main faults in the time frame of 1000 years [10].

In this work, the numerical model of the Tubåen and Nordmela formations in the Snøhvit field with heterogeneous porosity and permeability has been developed based on 3D seismic, core and log data. The period of injection of CO_2 is 30 years, with approximate 23 million tons of CO_2 injected in one well into the Tubåen formation. The numerical model was run with several scenarios simulating CO_2 injection and predicting the behavior of CO_2 in the reservoir in 5000 years by applying hysteresis properties of relative permeability. The overall aim of the study was to investigate and evaluate more accurately CO_2 behaviour during long-term storage and storage capacity in the Tubåen formation, in the Snøhvit field, with special focus on the long-term potential for residual trapping. An earlier study from the Sleipner field has given the result that two thirds of the CO_2 has not reached the top of the formation and 40% of CO_2 was estimated to be trapped residually [11]. CO_2-enriched water-phase convection (due to density differences) was also considered in the model. The diffusion coefficient of CO_2 in formation water has been determined to be in the range from 4.5×10^{-4} to 4.7×10^{-4} cm^2/s in reservoir condition of 83ºC and 178 bars [12]. When it comes to the slow mineral trapping, the Tubåen formation is dominated by quartz with minor reactive minerals such as feldspars. This mineralogy provides little potential for long-term trapping [3, 4] and has therefore not been considered in this paper.

2. Overview of the Tubåen formation & Snøhvit field

2.1 Overview

The Snøhvit field, discovered in 1984, is located in the southwestern Barents Sea, about 130 km off the Norwegian coast, northeast of Tromsø in northern Norway (figure 1).

The Tubåen formation is in the lower part of the Lower to Middle Jurassic strata that consists mainly of sandstones interbeded with thin shale layers deposited in a shallow marine to coastal plain environment with fluctuating coastlines [3]. The target for CO_2 storage is the thick sandstone bodies within the Tubåen Formation (figure 2). These sediments are interpreted as representing estuarine deposits.

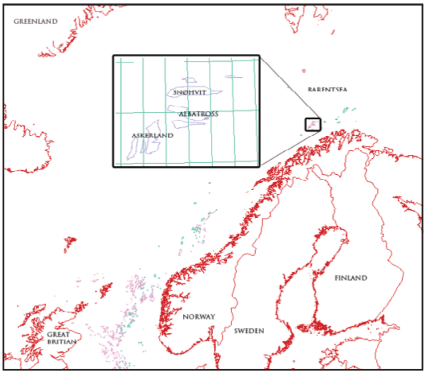

Figure 1 Snøvhit location [13] .

A small gas accumulation is found in the upper part, at the crest of the Snøhvit structure. The conformably overlying Nordmela Formation has silty shale and very fine grained sandstones in the lower part, overlain by fine-grained sandstones [3] and is considered as a cap rock preventing CO_2 from moving upward. The overlaying Stø formation is gas reservoir is currently being produced.

Tubåen formation has porosity in the range around 15%. Formation water has salinity of 168g/l calculated from [14]. The reservoir temperature is 98 ºC and the formation pressure prior to injection was about 265Bar at the target segment. In Snøvhit the reservoir is laterally restricted by faults orienting in the eat-west direction. The sealing of the main faults is an uncertainty factor investigated in a previous study [10]. This model studies the pressure build up in the Tubåen formation assuming non-conductive faults.

2.2 Fracture pressure

The reservoir fracture pressure is a key value to estimate the feasibility to inject CO_2 into a formation. Fracture pressure data is available for the Snøhvit field down to approximately 2500 meters (Figure 3), and fracture pressures for deeper units is therefore uncertain. Additional complications rise from the fact that fracture pressures are different from different rock types even at the same depth.

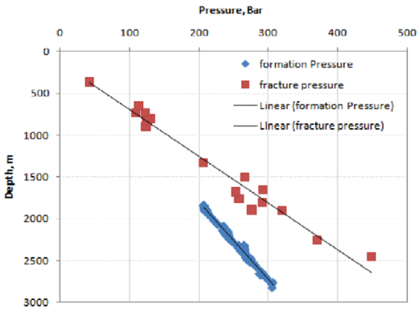

Figure 3. Fracture pressure in Snøvhit field

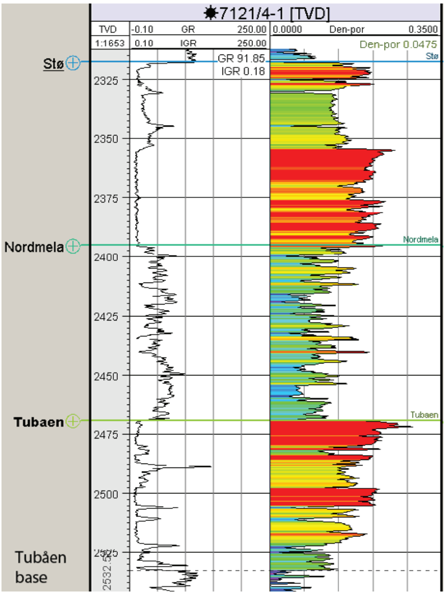

Figure 2. Log data of the well 7121/4-1: red color indicates good porosity, green and blue is low porosity (data from NPD: http://www.npd.no/engelsk/cwi/pbl/wellbore_documents/135_02_Completion_log.pdf)

3. Numerical model

The model consist of 73920 cells (120×44×14) with the cells dimensions: 300m×300m×variation in the Z-direction. The simulations were run using the ECLIPSE 300 simulator. The injection well was based on the real location defined to inject CO_2, the vertical perforation is opened nearly vertical injection into the Tubåen formation. The simulation rate was according to the planed 23 Mtons CO_2 over 30 years.

The numerical model with heterogeneous porosity was developed based on 3D seismic and log data. Permeability was calculated from the porosity-permeability relationship of core plugs in the two wells 7121/4-1 and 7121/4-2 (figure 4).

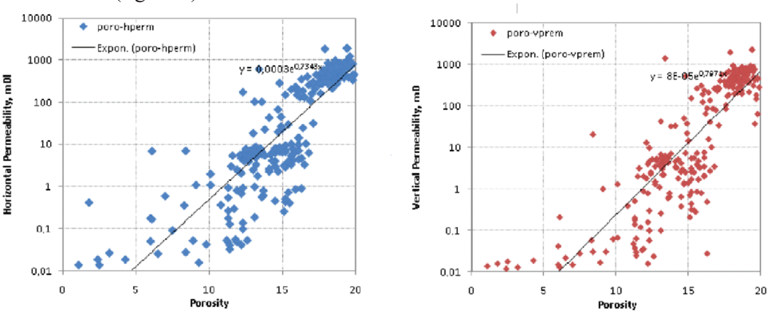

Figure 4. Porosity-permeability relationship in horizontal and vertical direction (data from the report of Statoil: Routine core analysis well 7121/4-1, 7121/4-2, NPD)

3.1 Fluid properties, PVT

The fluid model is compositional and run as follows:

The reservoir has been defined to consist of saline water (168g/l Nail) and a small gas cap at the crest of the structure. Components of the gas are taken from sample 2 at the depth 2470m in the well 7121/4-1 (Table 1). The gas water contact reported is 2473m in the Tubåen formation at the same well.

Calculation of CO_2 solubility and density of the aqueous phase were based on the Pang Robinson Equation Of State (EOS) [15] and modified following the suggestions of Storewide and Whitson to obtain accurate gas solubility [16].

Table 1. Gas cap components, sample in the well 7121/4-1 at 2470 m (data from NPD website: http://www.npd.no/engelsk/cwi/pbl/geochemical_pdfs/135_1.pdf)

Component	Mol
CO_2	4.97
N_2	2.74
C_1	82.14
C_2	5.07
C_3	2.51
i-C_4	0.41
n-C_4	0.84
i-C_5	0.28
n-C_5	0.29
C_6	0.51
C_7+	0.24
Total	100.00

3.2 Relative permeability and hysteresis

Relative permeability and capillary properties of two phase brine and supercritical CO_2 in the Tubåen formation were adopted from a series of experiments for CO_2-brine systems under the conditions that are correlative with the in-situ conditions, i.e. temperature of 98 °C, initial pressure of 265 bars, and salinity of 168g/l [14]. The relative permeability curve of sample Cardium 1 [17] could be applied for Tubåen formation with correlative conditions (figure 5) due to the lack of data. Hysteresis property of permeability was applied for the model to see the effect on the residual trapping.

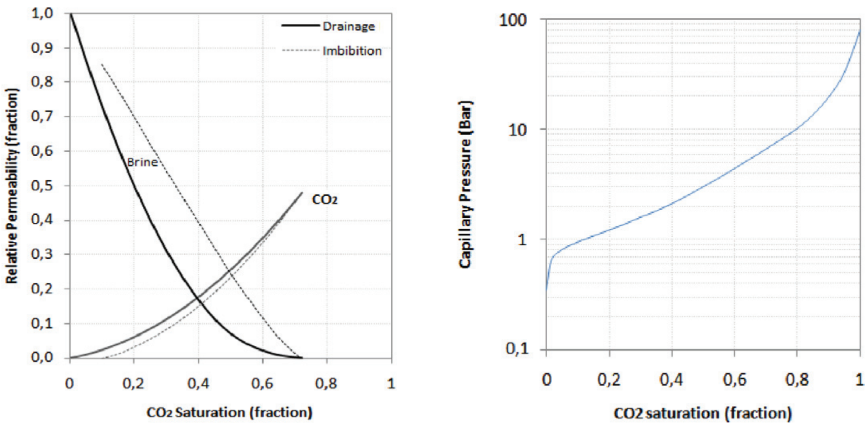

Figure 5. Relative permeability and capillary curve [17]

4. Results

4.1 No pressure constraint

At the end of the 5000 years simulation, the pressure had reached to about 543 Bar (figure 6a). The bottom hole pressure, however, had increased to very high levels and reach up to 815 Bar at the end of the injection. The planned 23 Mtons injection of CO_2 during 30 years is equivalent to approximate 1.2×10^{10} m^3 at standard condition (figure 6b). In that case, reservoir pressure increased up to 560 Bar after 30 years injection. After the injection stop, the reservoir pressure decreased a bit due to CO_2 dissolving into the aquifer. This injection rate was therefore not feasible because the pressure increased to levels significantly higher than the fracture pressure.

Because the problem is the increasing pressure, water alternative gas injection (WAG) to prevent the CO_2 plume from moving upward or fingering may not be feasible in this reservoir.

4. 2 Fracture pressure constraint

The fracture pressure of each rock formation is different, and fracture pressures of a rock formation are different at different depths. Due to poor data in fracture pressure at the injection depth of the Tubåen formation and from the data of fracture pressure of formations in Snøhvit field (figure 3), constraint for bottom hole pressure applied at the injection depth in average was about 440 Bar. If this value is applied as a maximum allowed bottom hole pressure, i.e. the injection rate is reduced as this value is reached, the amount that can be injected over the 30 years period is significantly reduced. This is seen in figure 6 as the BHP constraint case, and it is evident that the volume of CO_2 injected decreases significantly to about one thirds of the planned volume.

The distribution of the CO_2 plume, seen as moles of CO_2 per rock unit after 30 years injection and 5000 years of storage, is shown in figure 7. After 5000 years, a part of the CO_2 has reached the cap rock and may potentially penetrate through the cap rock (figure 7d)

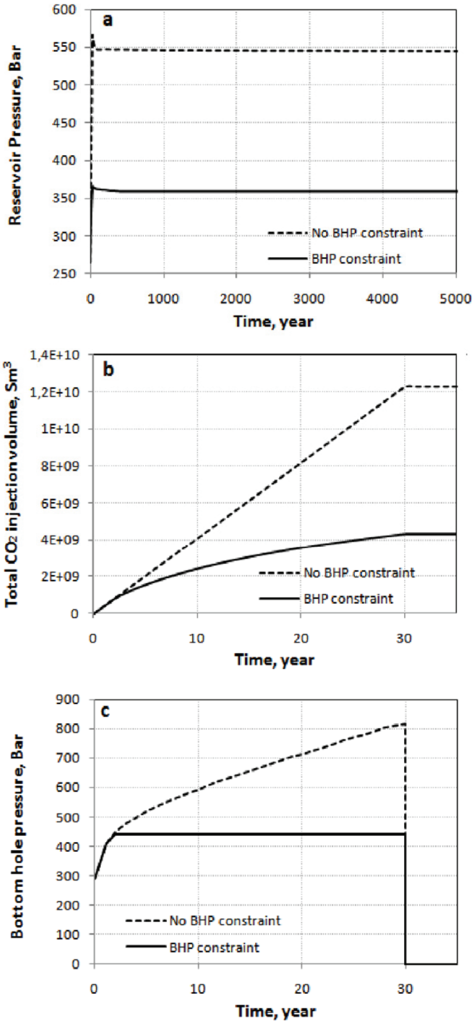

Figure 6. Reservoir pressure profile in 5000 years CO_2 storage (a), total CO_2 injected volume (b) and bottom hole pressure (c) in 30 years – injection period, BHP constraint is the base case.

4.3 Hysteresis effect

With hysteresis applied for the model, the reservoir pressure behavior differs minor. However, the distribution of the CO_2 plume observed is less spread out (figure 8a) and concentration of CO_2 in the area near by the injection well is higher due to small CO_2 bubbles strapped in the pore space.

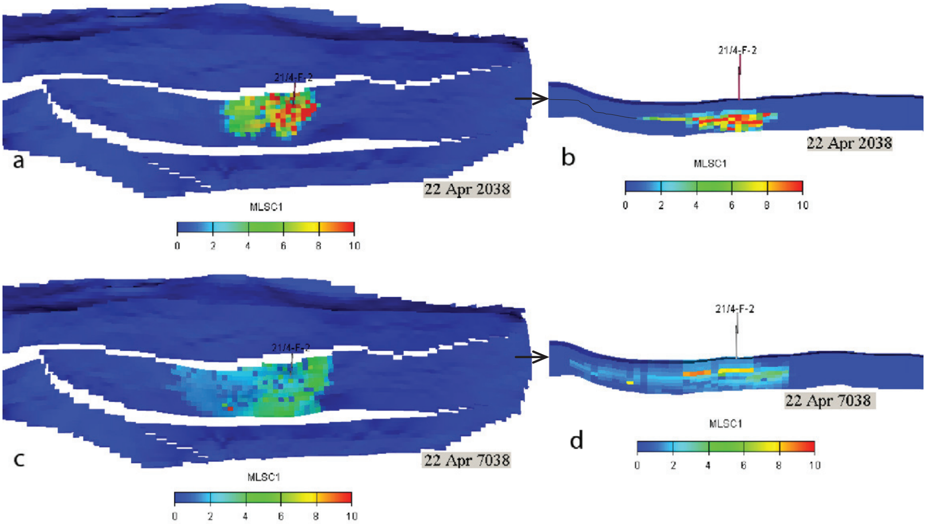

Figure 7. MLSC1: mol of CO2 per unit rock; CO2 plum after 30 years injection (a) and after 5000 years storage (c) observed at the top layer of Tubåen formation (layer 4), cross-section (east-west) cut through injection well (east-west) after 30 years injection period (b) and 5000 years (d), with the permeability property and diffusion of CO2 in to the caprock, after 5000years CO2 can penetrate through the cap rock-Normela formation (d).

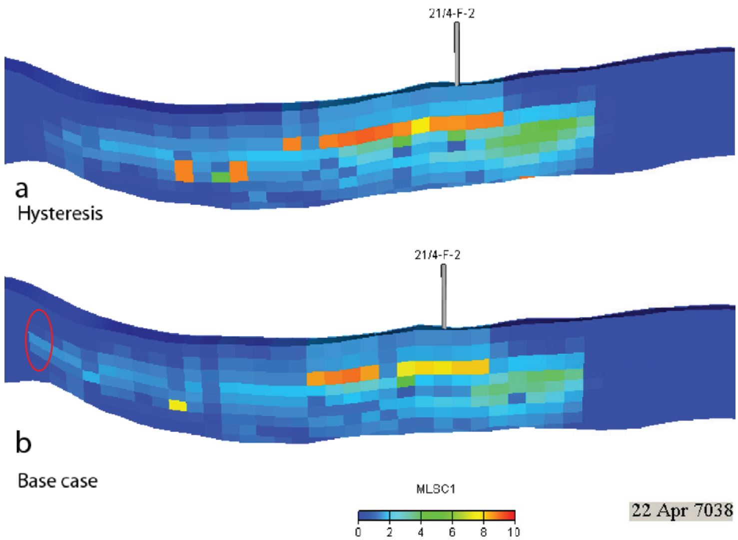

Figure 8. MLSC1: mol of CO_2 per unit rock; CO_2 plume after 5000 years storage observed in the cross-section (east-west) cut through injection well; (a) Hysteresis property applied (b) No hysteresis property, CO_2 plume is more spread out.

4.4 Diffusion

When taking into account diffusion, the simulation shows that CO_2 dissolution and diffusion into water that results in a downwards migration of the water because of the increased aqueous phase density. Therefore, that leads CO_2 plume to spread out less. At the top of Tubåen formation, the area spread out of CO_2 plume is smaller in the case of diffusion calculated than the case no diffusion, figure 9. In the diffusion case, reservoir pressure decreases more, after 5000 years, than the base case (no diffusion) and the hysteresis case due to diffusion triggering a larger CO2 volume dissolution. And with long period such 5000 years, diffusion transport could be considerable and CO2 penetrated through caprock (fig 7)

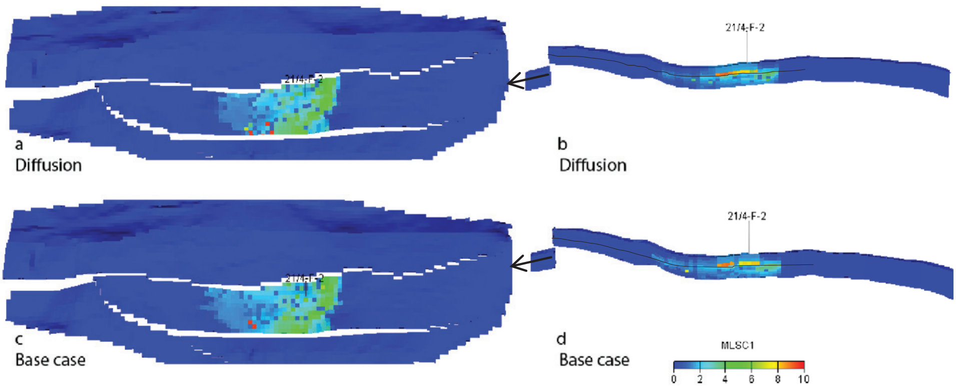

Figure 9. MLSC1: mol of CO_2 per unit rock; CO_2 plume after 5000 years storage observed in the top layer of Tubåen formation and the cross-section (east-west) cut through injection well; (a, b) Diffusion calculated (c, d) No diffusion, CO_2 plume is more spread out.

5. Discussion and conclusion

To prevent fracturing due to increasing pressure, the bottom hole pressure constraint was applied. This leads to a considerable decrease in the amount of CO_2 injected over the 30 years of injection, or alternatively a longer period of injection at lower rates. With hysteresis properties applied, reservoir pressure behavior was the same as the base case (no hysteresis); however, the CO_2 plume was distributed over smaller area than in the base case. Similarly to the case of hysteresis, the diffusion flow case showed that the CO_2 plume distributed over a smaller area than in the base case, but reservoir pressure decreased more than the other two cases.

The sealing capacity of the main faults is one of the uncertainties [10]. In this model, faults are assumed to be closed, because the production of gas from the reservoir in the Stø formation is not connected with the small gas accumulation in the Tubåen formation. During CO_2 injection, pressure increase may activate the main faults. However, the pressure threshold to activate the faults is unknown and this scenario is not included in this study.

The application of relative permeability curves and hysteresis properties of the fluids which is not from the reservoir could result in errors in the forecasting results. Experiments to investigate the behavior of supercritical CO_2 in the reservoir rock at reservoir conditions are necessary to perform, and the experiment results may lead better estimates of the CO_2 and pressure migration. Critical gas saturation is a parameter affecting to the amount of CO_2 trapped by residual trapping mechanism. Another source for uncertainties and errors is the petrophysical properties and the discretization of these properties.

Finally, to test if the geological model and the numerical simulations can predict the short and long-term behavior of the CO_2 injection, the results should be compared to historical data obtained after the 2008 Snøhvit injection started.

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